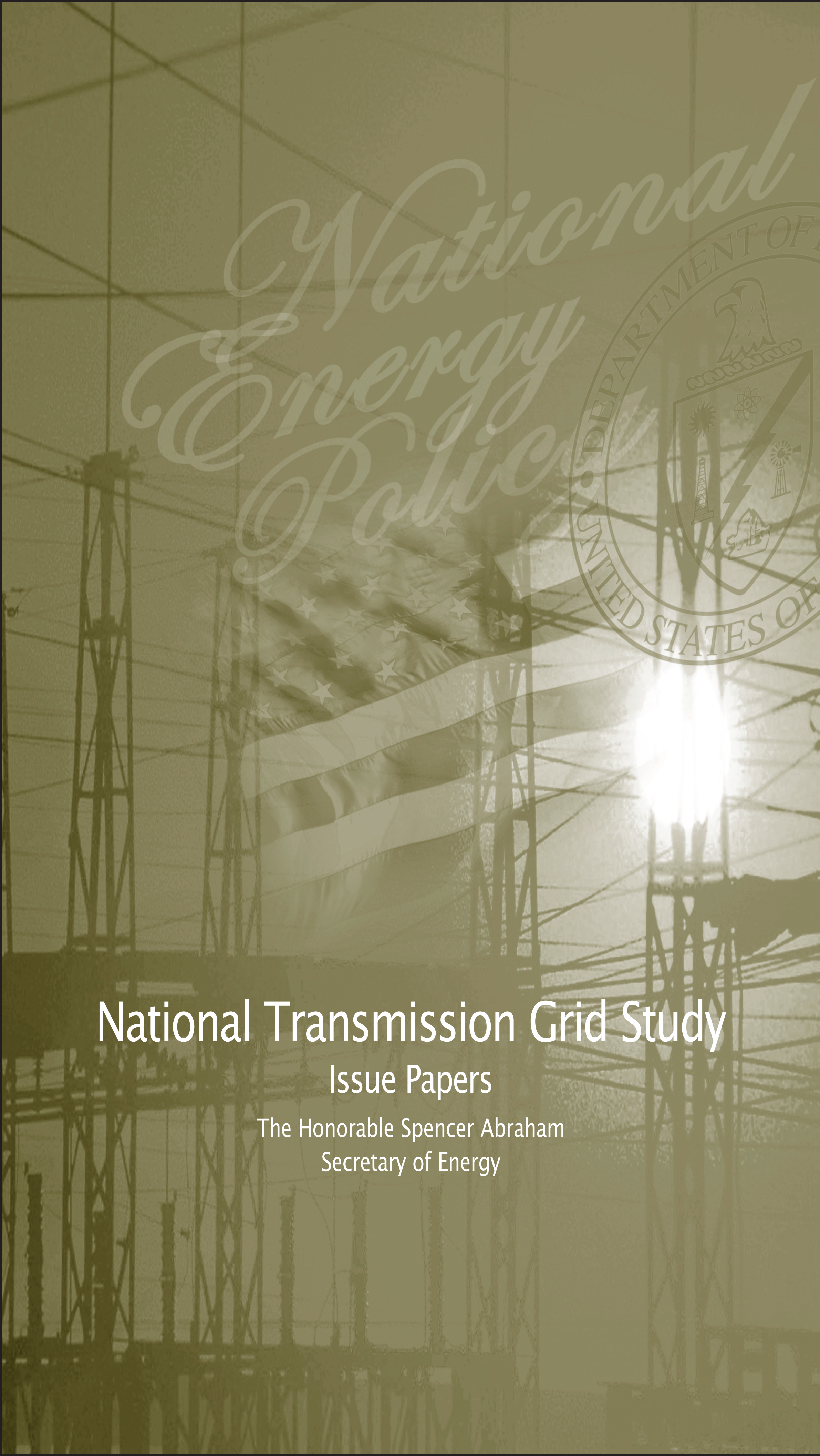

National Transmission Grid Study

Issue Papers

The Honorable Spencer Abraham
Secretary of Energy

U.S. Department
of Energy

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Transmission System Operation and Interconnection

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Reliability Management and Oversight

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Alternative Business Models for Transmission Investment and Operation

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List of Acronyms

AC	Alternating current
ACE	Area control error
ACSR	Aluminum conductors steel reinforced
AEP	American Electric Power
AGC	Automatic generation control
ASD	Adjustable speed drive
ATC	Available transfer capability
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CDEC	Centro de Despacho Económico de Carga
COE	Corps of Engineers
CPS	Control performance standard
CREPC	Committee on Regional Electric Power Cooperation
CSC	Commercially significant constraint
CSC	Convertible static compensator
DC	Direct current
DCS	Disturbance control standard
DG	Distributed generation
DOE	U.S. Department of Energy
DSA	Dynamic security assessment
ECA	Electric Consumers Alliance
EEI	Edison Electric Institute
EIA	U.S. Energy Information Administration
EMF	Electromagnetic field
EMS	Energy management system
ERCOT	Electric Reliability Council of Texas
ERO	Electric reliability organization
FACTS	Flexible AC transmission system
FCTTC	First contingency total transfer capability
FERC	Federal Energy Regulatory Commission
FGR	Flowgate right
FTR	Financial transmission right
GIL	Gas-insulated transmission lines
GPS	Global positioning system
GTO	Gate turn-off

HTSC	High-temperature super-conducting
HVDC	High-voltage direct current
IES	Intelligent energy system
IPO	Initial public offering
IPP	Independent power producer
ISO	Independent system operator
ISO-NE	ISO New England
ITC	Independent transmission company
kV	Kilovolt
LADWP	Los Angeles Department of Water and Power
LMP	Locational marginal price
MAPP	Mid-Continent Area Power Pool
MISO	Midwest Independent System Operator
MRD	Market redispatch
MWh	Megawatt hour
NAERO	North American Electric Reliability Organization
NARUC	National Association of Regulatory Utility Commissioners
NEPA	National Environmental Policy Act
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Council
NETA	New Electricity Trading Agreement
NGA	National Governors Association
NGC	National Grid Company
NPC	National Petroleum Council
NTG	National transmission grid
NTGS	National Transmission Grid Study
NYPA	New York Power Authority
O&M	Operation and maintenance
OASIS	Open Access Same-Time Information System
OPF	Optimal power flow
OTC	Operating transfer capability
PBR	Performance-based regulation
PCCIP	Presidential Commission on Critical Infrastructure Protection
PCR	Price-cap regulation
PDC	Phasor data concentrators
PG&E	Pacific Gas and Electric
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PMA	Power marketing administration
PMU	Phasor measurement unit

PPL	Polypropylene paper laminate
PPSM	Portable power system monitor
PSAM	Power system analysis monitor
PSC	Public service commission
PTDF	Power transfer distribution factor
PUC	Public utilities commission
R&D	Research and development
RMS	Reliability Management System
ROR	Rate of return
RTO	Regional transmission organization
SCADA	Supervisory control and data acquisition
SMES	Superconducting magnetic energy storage
SVC	Static-var compensator
TANC	Transmission Agency of Northern California
TCSC	Thyristor-controlled series capacitor
TLR	Transmission loading relief
TO	Transmission owner
TSO	Transmission system operator
TSP	Transmission service provider
TVA	Tennessee Valley Authority
UPFC	Unified power-flow controller
WAMS	Wide-area measurement system
WAPA	Western Area Power Administration
WGA	Western Governors' Association
WSCC	Western Systems Coordinating Council
XLPE	Extruded dielectric polyethylene

Transmission System Operation and Interconnection

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Introduction

Stated simply, the ultimate objective of the transmission system is to deliver electric power reliably and economically from generators to loads. Power systems are large, highly complex, ever-changing structures that must respond continuously in real time. Electricity must be produced and delivered instantaneously when it is demanded by a load. Power outages are not acceptable, so the system must also tolerate sudden disruptions caused by equipment failure or weather. And the system must perform as economically as possible, with transactions and sales monitored accurately.

Another distinctive feature of the electricity system is its inherent dynamic effects, which must be considered at all times even though they are difficult to explain and fully anticipate. Dynamic effects can be illustrated if we liken the power system to a large ballroom with many chandeliers. Each chandelier (system load) is connected to one or two other chandeliers by (big) rubber bands (the transmission lines). At strategic points these rubber bands are also attached to the ceiling (these rubber bands, which support the whole structure by being attached to the ceiling, represent the generators supporting the system). The whole structure is quite precarious. Not only must it be strong enough to support the chandeliers, but the loss of any rubber band must also be tolerated. Because the loss of a rubber band will set the whole pattern of chandeliers in oscillatory motion, the system of interconnecting rubber bands (the transmission system) must be designed so that these oscillations do not become destructive and cause some or all of the whole ensemble to crash to the floor.

This paper addresses the operation of the U.S. electric power system in its evolution from a historic structure of regulated, vertically integrated, regionally franchised utilities to the present-day market in which competition and entry by new participants is encouraged. Our specific focus is the impact of this industry restructuring on system operations. Our analysis presumes that the current structure of interconnected generators and loads will not be fundamentally altered. Examples of fundamentally different structures for the delivery of electricity that are not considered here include such possibilities as the provision of electricity to customers by means of isolated, distributed generators at every customer site. Another drastic alternative that we do not consider would be the use of direct current (DC) transmission as the backbone of the entire system. The cost of this alternative for the entire grid would be prohibitive. We presume that if these more radical options are incorporated to some degree, they will be integrated into the existing, conventional alternating current (AC) generation supply and delivery scheme. New generation is presumed to be either connected or connectable to the existing grid. Likewise, we presume that control of the system will continue to require real-time coordination between production and consumption, so we do not address electricity storage (although increased use of energy storage whenever the economics justify it can be readily incorporated into the current or any future system structure). The main impediments to energy storage are the cost and the efficiency of the technology (a great deal of stored power is lost once it is reconverted back to electricity). In short, as we address power system operations and interconnection, we assume that most of the fundamental requirements for system operation cannot change although the rules for operating the system might (and most likely will) be altered.

Traditional power system operation relies on the concept of independent but coordinated functioning of multiple "control areas." A control area is a (usually contiguous) portion of the system (lines, transformers, generators, loads, and other equipment) under the supervision and control of a single operator (or group of operators at a single locations or under a single administrative structure). Control center operators maintain the system's integrity—prevent outages and insure reliable operation—by following reliability rules that every control area enforces. The rules are intended to balance supply and demand without creating overloads, congestion, or other similar problems. Operations are based not only on maintaining a balance between supply and generation but also on controlling the frequency of the system in a distributed manner. Sufficient reserves are provided throughout the system so that it can tolerate the loss of any one component at any time (the "N-1 criterion"). We do not anticipate that either requirement will change as result of restructuring.

The remaining sections of the paper address system operations as follows:

- Traditional operating policies and protocols associated with the role of operators.
- The evolution of system operations into a competitive environment by considering two models:
  - The "reliability-driven model," in which markets are permitted to operate but reliability concerns limit which transactions can take place, and, when necessary, previously approved transactions are curtailed in the name of reliability,

    and

  - The "market-driven model," in which the objective is to create a market that values reliability sufficiently and is nimble and precise enough that reliability problems are solved by market responses to price signals, which reflect system limits and thereby embody reliability rules in the prices paid to generators or paid by consumers at various times and locations.

- Additional possible directions in which system operations and the transmission grid might evolve.

- Alternative scenarios and specific recommendations.

The objective of this paper is to delineate the conditions that will permit the creation of a power system that supports and encourages competition without compromising reliability or operability. An underlying premise is that a properly designed market structure that reaches all the way to system operations (i.e., an increased use of markets for meeting operational needs) will yield higher throughput of electricity and more appropriate utilization of the transmission grid than is currently the case. Such a market should include sufficient incentives to grid operators to maximize their throughput not only in real time but also through greater use of existing assets, e.g., by optimizing maintenance schedules, increasing live maintenance, maintaining appropriate inventories of spare parts and components, and using dynamic line ratings to maximize grid utilization. In the long term, this market structure should also encourage appropriate transmission grid expansion.

Traditional System Operation Policies and Protocols

The primary, traditional objective of power system operation is to maintain system integrity. This means that uncontrolled cascading outages must be prevented. Maintenance of system integrity is referred to as "security." Closely related to the notion of security is the notion of "reliability." Although we use the terms interchangeably in this paper, reliability is generally understood to include the concept of adequacy of supply, which means that methods for procuring reliability can be devised. At bottom, however, both terms refer to the avoidance of unintended blackouts.

The system is expected to maintain its integrity and continue to operate properly without a major disruption even when a component fails. For example, if an overhead line fails because of a lightning strike, the resulting fault requires that the line be taken out of service immediately to prevent a further expansion of the problem or damage to system components. The protective relaying system is designed to accomplish this automatically and more or less instantaneously. The overall power system should, however, continue to operate even with this line out of service and in spite of the transient disruption caused by the fault. Likewise, even if the largest generating unit were to suddenly go out of service for any reason, the system should be able to recover and continue normal operation. Normal operation means that (1) the frequency of the system stays within acceptable bounds, (2) all voltages at all locations are within required ranges, (3) no component is overloaded beyond its appropriate rating, and (4) no load is involuntarily disconnected. The North American Electric Reliability Council (NERC) has, over the years, developed a number of criteria intended to assure this degree of system reliability and security. Regions such as the Western Systems Coordinating Council (WSCC) and the Electric Reliability Council of Texas (ERCOT) follow similar objectives and protocols.

A second traditional objective of power system operation is to minimize operating costs. Thus, a system operator traditionally had two roles: to assure reliability and, in effect, run a real-time market. When conditions were tight, security would take priority. Otherwise, economy of operation dictated the operator's objectives.

Tools for Managing Operations

In order to accomplish the two (sometimes conflicting) objectives of security and economy, system operators have at their disposal a number of tools to manage the system in real time. These tools range from Supervisory Control And Data Acquisition (SCADA) systems that monitor and display the status of the system in real time to more sophisticated tools such as State Estimator programs. A State Estimator program gathers all available telemetry data (real-time measurements) on the system and gives a complete, real-time picture of system status. An accurate, error-free picture of what is going on in the system is an important precondition for running the system reliably.[1]

Operators also have means at their disposal for direct control of the transmission grid. These include control of switching operations (inserting or removing lines and/or transformers), shunt injections (usually reactors and capacitors inserted at buses, mainly as a means to regulate the voltage profile), and control of regulating transformers and other series- and shunt-adjustable devices. Operators can also adjust system area set points to help regulate system frequency, control flows on exports/imports to/from other systems, and maintain the Area Control Error (ACE) within specified bounds. ACE is the difference between the total power exported by a control area and the intended exports from the area, plus a component that represents the required contribution by that area to the control of system frequency. Control of interruptible load is also often within the purview of an operator. In emergencies, many operators also have control of feeders and ordinary system load.

Control Areas

Control areas are central to system operation and interconnection and have well-defined boundaries. Flows of power across control area boundaries are always metered and monitored. Although it may be possible to operate a large interconnected system functioning as one control area, the practical difficulties of doing so have been insurmountable to date. Even if the entire grid were to be integrated and operated as a single whole, it is likely that the notion of control areas would survive in some form as a practical means to attain distributed, decentralized, and redundant control. NERC is currently reviewing the notion of control areas in order to better adapt it to a competitive environment.

For both historical and practical operational reasons, every location in the system is assigned to a control area. Every control area in the system is "responsible" for balancing its generation with its load because the amount of electricity generated must equal the amount of electricity consumed, plus losses. Whenever there is insufficient generation, the entire system "slows down" (i.e., the frequency drops). The opposite occurs when there is excess generation. Because the entire interconnected system is so large, it is most practical to balance generation and load on an area-by-area basis. However, it is necessary to precisely measure how much power is being exported or imported by an area to know whether the area is balancing its generation and load. Gathering this information requires that every line or transformer connecting an area to any other area be accurately metered and monitored in real time, and all measurements be aggregated at a central location so that an accurate ACE can be monitored.

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[1]Improvements in the area of metering, monitoring, and state estimation are significant steps in improving the transmission grid. Although many improvements are currently technically feasible, investment in them has not been forthcoming for many of the same reasons that investment in new transmission has been lagging.

Related to the notions of control area and ACE is the concept of uninstructed deviations. As attempts are made to adjust the ACE for each area, errors inevitably accumulate because the control actions of generators (or loads, if permitted) are in reality different from what was intended or instructed; these are uninstructed deviations. From these deviations arises the notion of "energy imbalance" as an ancillary service. Consistent errors in one direction or the other by a number of participants (along with random changes in demand) also give rise to frequency drift, which must be corrected with frequency regulation. In traditional systems, uninstructed deviations have been handled by having systems "pay back" the energy at a later corresponding period (peak or off peak). This approach has worked well over the years, but as we shall see below, it needs to be revisited.

The question of whether the system would be better off with more or with fewer control areas (or whether control areas might be replaced by a superior concept) has not yet been answered. It may be desirable to have more numerous, smaller control areas to avoid communication problems, handling of large amounts of data, and complexity that might make the system difficult for operators to understand. More control areas, however, mean greater need for coordination among them and a considerable increase in the number of monitored tie lines that must be precisely accounted for at all times. Fewer, larger control areas, however, might make the system more vulnerable to the effects of failure of one control center. One key point is clear: all control areas need to follow uniform (or at least compatible) practices for both reliability and business activities.

Generation Redispatch

In traditional power systems, an additional tool for system operators to maintain secure operation of the system is generation redispatch, in which operators send orders to generators to increase/decrease their output based on system security needs. In many systems, operators have access to tools that permit them to estimate the cost (a proxy for price) of their actions. Thus, operators generally have at least some awareness of costs. Increasingly, however, a larger portion of system generation (and also of load) is being bought/sold under merchant contracts that specify specific levels of production at any given time. This effectively eliminates adjustment of generator output as a primary tool for maintaining system security unless contracts are written to grant the system operator this type of control. One approach to returning this control to the operator is to have generators offer incremental/decremental (inc/dec) bids for their output. That is, generators indicate the price at which they are willing to increase their output by one MW (inc bids) or decrease their output by one MW (dec bids), with limits for both. This arrangement permits the operator to reschedule generation as before, at an explicit price. If an inc bid is exercised (a generator is asked to increase its output), the price of increasing the generator output by one MW becomes the marginal price of electricity at the generator location (this cost is also known as the locational marginal price, or LMP).

Depending on the design of the market, the costs of redispatch can be either absorbed as part of the cost of system operations and paid by all participants using a cost structure in which these expenses are shared, or these costs can be charged to those "responsible" for the need to incur redispatch costs. It is more efficient to avoid the sharing of expenses by all because this approach tends to create incorrect incentives, although for practical reasons and in cases of "common good" facilities, some sharing of costs by all is sometimes necessary. An example of this type of situation would occur when a badly located generator for the conditions may elect to produce power because it knows it will be paid the system price (which is high), thus helping create congestion and preventing other more valuable trades from taking place. The operator is then forced to incur a redispatch cost to eliminate the congestion, but since all share on the resulting added cost, the party most responsible for the congestion benefits.

Security

System security is achieved by making system operation tolerant of the outage of any component (some multiple outages are also considered). That is, the outage of any single system component (or predefined set of components) should not cause a cascading outage of equipment that leads to a total or partial blackout. The system should be secure even when an outage is the result of a "shock" such as a short circuit or fault on a component prior to the component's outage. A system that is resistant to the outage of any one component is said to be N-1 secure. In a planning time frame, N-1 security means that the intact system must be able to tolerate the outage of a component. In a planning timeframe, some allowance is often made for limitations that the system will encounter in real time. One way in which this is sometimes done is by considering the simultaneous failure of any one line and any one generator when doing planning time frame studies. In an operations time frame, however, N-1 security means that the current system must be able to tolerate the "next worst" contingency. Because an actual operating system may have already sustained the outage of one or two components, this is tantamount to operating the system in an N-2 or N-3 condition from the planning point of view. Previous contingencies are "sunk events" from the perspective of system operations. This means that, once a contingency occurs, meeting the N-1 criterion means considering the altered system, not the original system, as the new base case to which the criterion must be applied.

It is almost universally accepted that N-1 security is fundamental to system operation and that achieving this level of security is in roughly the same category as making sure that generation meets load: it must be done, regardless of cost. However, once the goal is to make the system N-2 or N-3 secure, cost and other similar considerations enter the picture. Operators have traditionally handled the threat of multiple contingencies adaptively. For example, operators have been known to "move" generation closer to loads when storms approach and the likelihood of an outage (or multiple outages) increases. "Moving" generation means increasing generation at a location near the load and reducing the output of generators far from the load (these actions must be taken together because balance between generation and load must be maintained). Because of losses in the system depend on the pattern of flows in the transmission system, and changes in losses also depend on transmission system status, an increase in load by 1 MW may require more or less than 1 MW to attain a new system equilibrium. By moving generation around under stormy weather conditions, operators are, in effect, treating the weather as a contingency. Formalizing criteria for taking such measures is not always easy, but efforts are under way to do so. In a traditional environment, the costs of such redispatch are borne by all, but in a competitive environment these costs will be differentiated by time and location and borne in accordance with the marginal price of electricity at any point in space and time. That is, every node in the system has a possibly unique marginal locational price for electricity (an LMP) which, in theory, reflects the cheapest way to deliver one additional MW of electricity to the location in question without exacerbating problems on any line or other limits.

To maintain N-1 (or better) security and achieve a secure operating point that is resistant to cascading failures requires several preconditions:

- The system must have sufficient spinning reserves. Spinning reserves are generators that can instantaneously increase their output when a decrease in frequency signals that load is exceeding generation. If there are sufficient spinning reserves, system frequency will, after the loss of the largest generator, automatically settle to a new, acceptable value as a result because a sufficient number of other on-line generators will immediately pick up the deficiency. Generators already at their limit plus other generators that do not have Automatic Generation Control (AGC) cannot be counted on to provide spinning reserves. (The outage of a component may be caused by a fault, which may pose additional problems of a dynamic nature.) There is no fundamental reason why demand (load) could not provide spinning reserve by reducing consumption in response to a frequency drop. Traditionally, demand (particularly induction motor loads) provides spinning reserves by reducing consumption as the frequency drops. However, this automatic reduction does not take place in most new adjustable-speed drives (ASDs), which are electronic motor controls that adjust motor speed independent of system frequency (unless programmed to do otherwise). The increased penetration of ASD loads is reducing the "free" spinning reserves that loads have traditionally provided to the system.

- The system must have sufficient supplemental reserves to maintain system integrity after the initial shock of a contingency. As the result of an initial outage, some components may end up operating beyond their sustainable capability or may offer the system only limited-term assistance. In either case, it is necessary to restore operating conditions that are sustainable more or less indefinitely so that the system is ready to sustain a further outage without a major cascading failure. In effect, the objective of supplemental reserves is to re-establish spinning reserve margins.

- Both types of reserves must be located so that they can deliver power as needed for every possible outage condition. While spinning reserve is being relied upon, this delivery takes place more or less automatically. When supplemental reserves are needed, it must be possible to rapidly maneuver the power system to a condition in which it is capable of delivering the needed power. Such power readjustment must be possible after every event.

There is likely to be a tradeoff between the location of reserves and the strength of the transmission system. If the system's transmission capability is very limited (or fully utilized), reserves for possible contingencies must be provided "locally" so that transmission is not necessary to access the reserves. If the transmission system has ample capacity available, the use of remote reserves is practical. For radial situations, this assessment is quite simple. In contrast to a network, a radial system has no loops and has only one way of sending power via the transmission grid; if that one link fails, the system is disconnected. The only options after the loss of the link are to generate power locally or to reduce load. In network situations with many possible contingencies and changing flow patterns, the assessment of adequacy of reserves in relationship to the availability of transmission capacity can be a difficult problem. If a control area relies on remote reserves, the transmission system must be able to deliver the reserve power when and if required. Although the distinction between radial and network situations is complex, proper handling of the complexities and subtleties of networks is the key to proper operation and design of power transmission grids.

A comment pertaining to reserves (as well as other "ancillary services") is that reserves and energy markets are in a sense complementary in grid operations but are substitutes in energy markets. As power markets mature, the market structure may evolve to encompass more open-market instruments, such as forward trading (this refers to the purchase of power ahead of the time where it is wanted rather than reliance on the spot or real time market for electricity). Another structure that can help with assuring adequacy of reserves that might evolve is the self-provision of reserves, where anyone in need of reserve services is responsible for providing it themselves.

Traditionally, operators have relied on experience, training, and prior off-line studies that specify parameters (often in the form of diagrams or nomograms) that indicate whether the current condition of a system is acceptable from a security point of view. Today, more and more operators also rely on sophisticated power-flow and contingency-analysis software that can assess system conditions in real or near-real time. Nomograms continue to serve a useful purpose to account for real-time incorporation of stability limits. If system conditions are determined not to be acceptable, the operator generally has at his or her disposal the tools mentioned above to help address the problem.

Balancing generation and load

A system operator is in charge of frequency regulation in addition to system security. Electric power customers expect that power will be a sinusoidal AC voltage waveform of 60 Hertz.[2] Many system and end user components rely on this frequency. However, without some control of frequency (frequency regulation), the frequency would quickly drift outside acceptable bounds as a result of even slight imbalances between generation and load. Responsibility for frequency regulation is almost universally organized based on control areas. As mentioned above, every formally defined control area must match its generation to its load. NERC rules (CPS1 and CPS2) specify exactly what is meant by proper balancing of load and generation. These two rules recognize the random nature of system variations and require the balancing of production and demand over designated intervals rather than at precisely all times (which would be virtually impossible). If a control area has "undergenerated" over a short period, it is expected to "overgenerate" to compensate for the shortage. This is accomplished by adjusting the ACE set point to increase the output of generators within the control area. In other words, areas adjust their generator outputs if necessary in order to balance power.

In addition to balancing load and generation, control areas handle transactions. Transactions are scheduled when the importing area schedules a net import and the exporting area schedules a net export. Even when private parties from different areas engage in transactions, the ACE must be adjusted. In a traditional operating environment, errors in energy exports or imports ("inadvertent errors") can accumulate. According to traditional rules, energy errors must be "paid back" in a later corresponding period (peak or off-peak). This rule implicitly assumes that (1) the accumulation of error is small and unintended, and (2) all peak-period energy has approximately equal worth as do all off-peak-period energy.

No matter how good energy-balancing rules are, some frequency "drift" can develop because of sluggish response of frequency regulation equipment, slight metering errors, and random factors; as a result, another

[2] This voltage is expected to oscillate between a maximum positive value and a maximum negative value 60 times per second, in a "smooth" manner following the shape of a mathematical sine wave. Departures from this waveform are called "harmonics." Departures in the frequency of oscillation are called "frequency deviations."

role of the ACE has been to bias generation to regulate frequency system wide. The definition of ACE incorporates a term that becomes negative when the frequency is above its set point and positive when it is below its set point. An additional correction can be made to the ACE in order to maintain the exact number of cycles over every time period (time correction or isochronous control). This time correction control is done by temporarily adjusting the set-point frequency.

Operating the System Economically

In addition to maintaining security and regulating frequency, a traditional system operator was also in charge of system economy. This meant that the operator sought a generator dispatch pattern that was not only secure but was as economic to operate as possible under the security criterion in effect (for example, the N-1 criterion). With a given mix of on-line resources, no constraints, and no losses, the optimum operating point is known to be the point at which the marginal cost of production is the same for every generator. When transmission losses are taken into consideration, penalty factors or other schemes can be used to determine the optimum operating point by adjusting the marginal cost of production according to the location of each generator in the system. When constraints (or contingencies) must also be considered, the problem becomes one of constrained economic dispatch. Finally, when the operator also takes into consideration other controls available (such as tap adjustments or voltage settings), the problem becomes in effect a nonlinear constrained optimization problem, better known as an Optimum Power Flow (OPF). In other words, the system operator can use generator outputs alone, or can use additional means of control in order to make the system work better. All traditional systems use some form of economic dispatch.

Constraints increase operating costs. Thus, the existence of a transmission constraint *in a traditional power system operated to minimize cost* causes a higher operating cost than if the constraint were removed. To the extent that eliminating a transmission constraint permits a more efficient operating point, greater transmission capacity lowers operating costs. If the constraint is in the flow on a line or transformer, it does not follow that merely adding a line or otherwise increasing the capacity around the constraint will always result in lower operating costs. It is possible that such actions will simply "move" the constraint to a different (and perhaps less desirable) location, with negative consequences for the system. Examples of relocating constraints by adding capacity exist in both theory and practice. An additional issue is the possibility that there may be multiple ways in which a constraint can be addressed, in whole or in part.

Tightly coupled to the problem of dispatch are the problems of operations planning and unit commitment. If an insufficient number of resources are "on line," (that is, already running and connected to the system) it may not be possible to respond to a particular contingency without shedding load. Because security is defined as the avoidance of (cascading) involuntary load curtailment, involuntary curtailment of load is almost never acceptable. To avoid load curtailments, traditional control systems have relied on unit commitment and operations planning to decide ahead of time which units should be in service at any given moment. Determination of the optimal schedule for units to be committed during any given period generally requires the solution of a rather involved mathematical problem known as a multi-period dynamic optimization. This means that one must figure out not only the best combination of units needed to run the system at any given future time, but also how that particular set of units affects the ability to run the system at a later time, since once a unit is on line it is often desirable to keep it on line (many units are designed to have minimum "up times"). True optimization is difficult to attain, so simpler heuristics and approximations are often used to make these decisions. For example, the problem is often solved in "whole hour" intervals, it is often solved for a one-week time horizon, and many units that are "known" to be on (e.g., nuclear plants) are not included in the mix. Another approximation often used is the assumption of a "perfect load forecast" over the interval under consideration. Market alternatives that shift some of the complexity of commitment decisions away from an operator to market participants have proven successful. Such strategies include reliance on "self-commitment," where units decide on their own when they want to be committed. The requirement that offered prices by any unit be monotonically increasing in quantity (even if its marginal cost of production decreases) is another strategy aimed at simplifying the operator's task.

Additional problems of system operation

Some other key problems related to system operation are complex and difficult to explain. These include dynamic problems (particularly the possibility of interregional oscillations between interconnected systems as were experienced for several years in the Western Interconnection), "loop flows," "unexplained flows," problems of reactive power and reactive power reserves, and problems associated with flow-control devices (phase-shifting transformers, some series flexible AC transmission system (FACTS) devices, and high-voltage DC (HVDC) transmission lines[3]). Interregional oscillations arise almost naturally in relatively weakly coupled systems with long transmission lines because of interactions between the controls of the governors and the exciters of the individual generators. The prevention of such oscillations generally requires system-wide studies that represent the dynamics of generators and their feedback controls. The most effective solution to these oscillations is often to install Power System Stabilizers at all or at least the most important generators. Stabilizers would not normally be installed except in cases of extreme need because of their cost and complexity. (Although the initial cost of purchasing a generator with appropriate power system stabilizer capability is higher than the cost of a generator without this capability, the added cost at initial purchase is significantly less than the cost of retrofitting a generator to add this capability.) All of these considerations add complexity to the problem of managing system operation.

Because power system stabilizers cost money, individual generators in competition with one another would not tend to install stabilizers; there is no direct benefit to the individual generator from installing a stabilizer unless the real-time value of a stabilizer is established (under many conditions, its value will be zero, but on a few occasions the value may prove to be extremely high) or a requirement is established that all generators must install this equipment and thus share in the burden of system stabilization. Specifically, the value of a stabilizer may prove crucial only under certain highly unusual conditions that may result as a consequence of several component outages and/or unusual load or generation patterns.

[3]A FACTS device is a high-power electronic device intended to rapidly control system flows and/or voltages. FACTS technology tends to be expensive to install and maintain but can alleviate many specific AC-system problems. HVDC refers to high-voltage DC transmission, in which a rectifier is used to attain high-voltage DC power which is subsequently reinverted to AC power (possibly at a different frequency). The advantage of HVDC is that it permits greater isolation between two regions of a system than AC transmission. However, the converter stations required at each end of an HVDC line stations are expensive and subject to many technical problems. Moreover, it is difficult (some argue that it is impossible) to build large HVDC networks.

Application of the N-1 Criterion

The N-1 criterion for system operation is deterministic. It requires that the system be able to tolerate the outage of any one component without disruption and does not concern itself with the probability of an outage. Even if an outage or contingency is highly unlikely, the criterion is still generally applied because system failure when a component is lost is unacceptable. The cost of meeting this criterion is not questioned; the criterion is generally considered as fundamental as the need to balance generation and load. (In practice, some probabilistic considerations do enter into the criterion in the definition of what constitutes a credible event worth guarding against. This issue is discussed in more detail in Kirby and Hirst, *Reliability Management and Oversight,* in this volume.) The consequences of a failure to balance generation and load are immediate and measurable: system frequency drifts. However, consequences of failure to meet the N-1 criterion may not be directly observable unless a critical component goes out of service. The absence of actual contingencies to reveal the failure to meet this criterion can create the false impression that a system is operating adequately when in reality it is operating at great risk.

The application of the N-1 criterion to generation outages is illustrated in Figures 1 and 2, which also show system reserves. Figure 1 illustrates the generator outputs. Figure 2 aggregates the outputs and the unused portion of the outputs (the reserves). Figure 3 illustrates a possible situation after one generator goes out of service. Likewise, Figures 4 through 6 illustrate the N-1 criterion for line outages. Initially all lines are below their flow limits. Figure 4 shows conditions before the outage, and Figure 5 shows conditions after the outage. Figure 6 illustrates a case where insufficient N-1 capacity has been reserved.

For radial connections, the N-1 criterion may be impossible to satisfy; if there is a single radial link feeding a particular load, there is no way to prevent at least some load outage if the link fails. The only way to avoid

Figure 1. Four generating units within one area. The height of the box represents the size of the unit. The shaded area represents the portion of the unit capability that is being utilized. Availability of reserves is represented by the unshaded area. For simplicity, only one type of reserve is illustrated. In reality, reserves in several time frames are of interest.

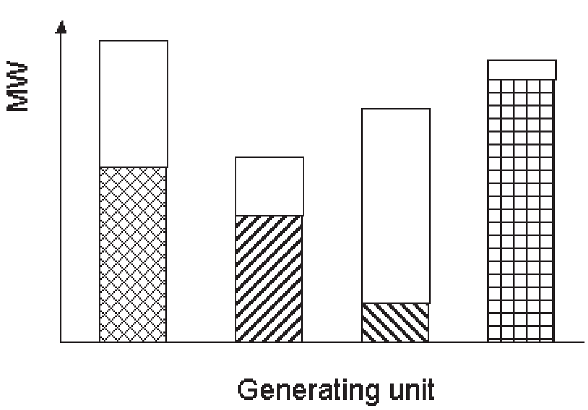


Figure 2. The vertical double-ended arrow represents the system demand (including losses, for simplicity). The stacked bars next to it illustrate how the generators are meeting the demand and the point at which total supply equals demand. Available reserves are illustrated by the rightmost bar.

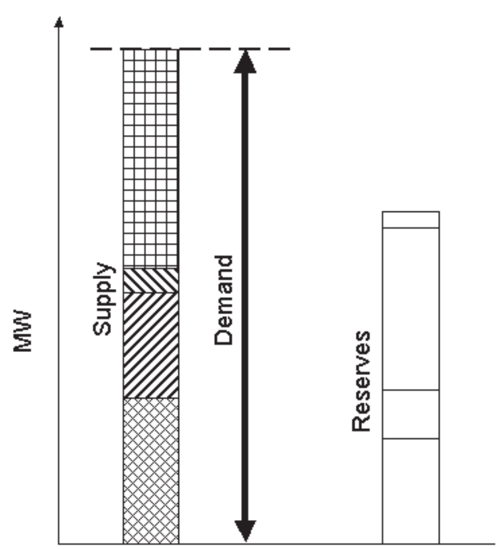


Figure 3. Outage of the largest generating unit requires reliance on reserves. In this example, we have assumed that one of the four generators goes out of service. We can see that the available reserves are enough to supply the load. The crossed-out bar suggests that the outage of the largest unit involved removal from the system of the unit itself as well as the reserves associated with the unit.

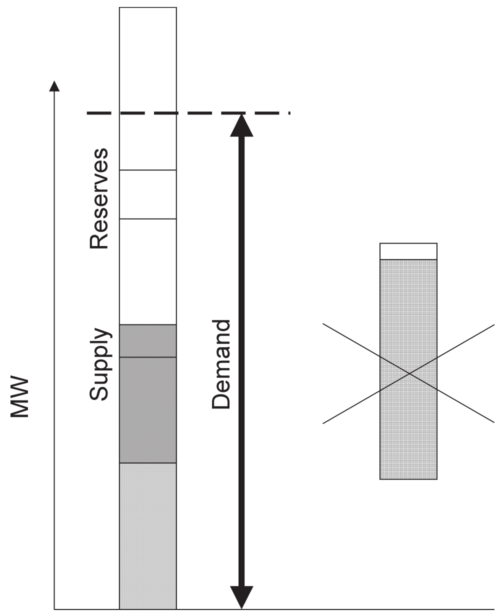


Figure 4. The operating condition flows on four potentially limiting transmission lines are illustrated. The solid portion illustrates the actual flow, and the unshaded region illustrates the capability of the line ("transmission reserves"). Flows can be bidirectional even though one limit is usually more likely than the other. In this example, the positive limits on flows are closer to being reached because all flows are in the positive direction.

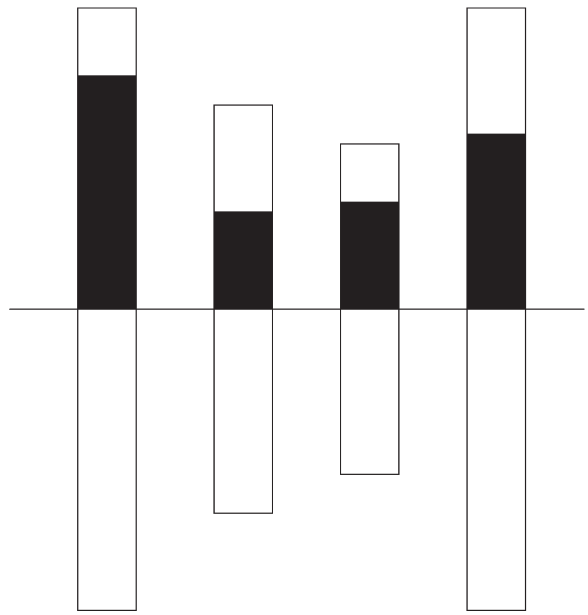


Figure 5. Flows after the outage of a line. The fourth flow in this example has been reduced by the outage. The N-1 criterion is satisfied because all new flows are still within acceptable bounds.

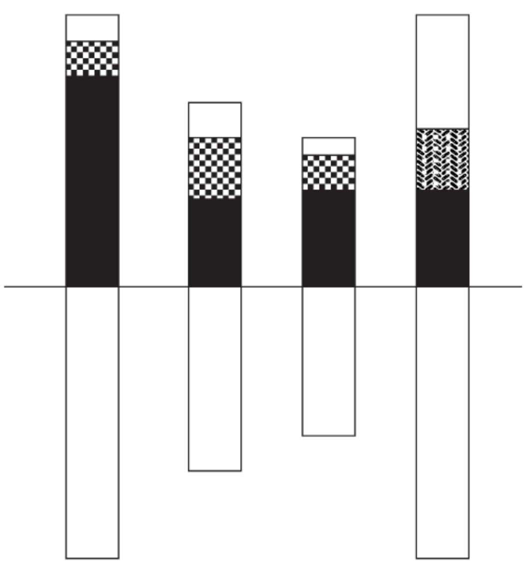


Figure 6. Flows after the outage of a generator. Under the conditions illustrated, the system does not satisfy the N-1 criterion because the outage of the generator results in an overload of the third transmission facility (the new flow is above the limit). Thus, although generation reserves may be adequate, the transmission system is unable to support the contingency flow.

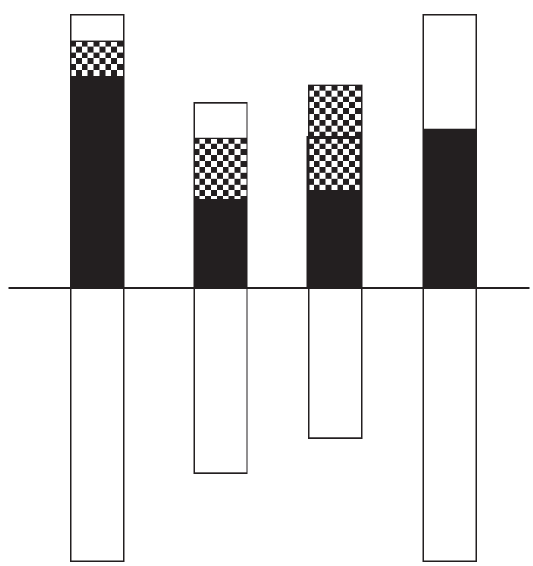


Figure 7. Disconnected (or weakly coupled) two-area system. In standard operational terminology, marginal operating costs are referred to as the system λ. The bold and unbold segments are used to designate distinct suppliers and to emphasize the lumpy nature of the supply curves. Marginal cost of production and actual conditions can give rise to significantly different marginal operating costs (and consequently significantly different marginal costs of delivering power to customers) in the two systems.

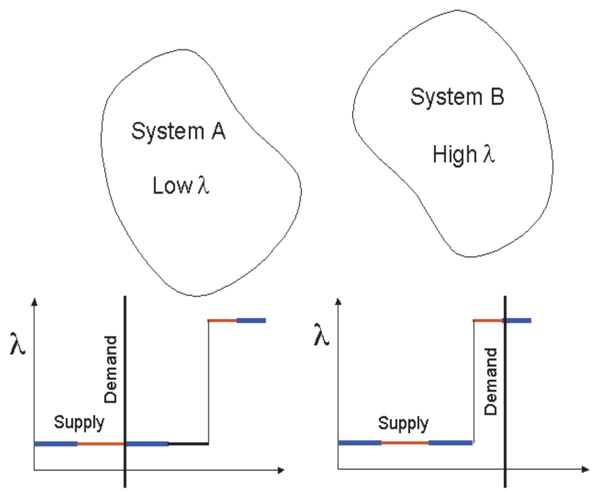
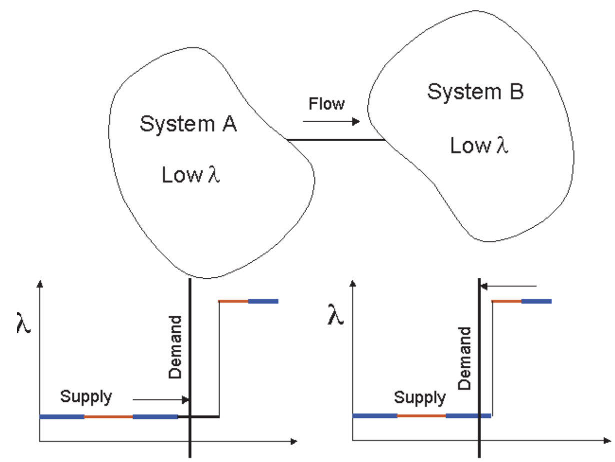


Figure 8. Construction (or expansion) of interconnection makes it possible to operate the system at lower marginal costs, resulting in cheaper production costs (that translate into end-user electricity rates) for system B without appreciably affecting the cost of system A.



an outage would be to have instantly available local generation or an energy storage unit at every load. The alternative is not to connect loads radially, which would be costly and complex.[4] The need for redundancy of transmission capability is the main reason that power systems are generally networks.

The N-1 criterion is often modified when increased security is important. In situations when it is obvious that the loss of a line or corridor is likely (for example, when a weather pattern makes it very likely that at least some lines will go out of service), the system can be operated in a more secure mode than usual, and an N-2 or -3 criterion can be used. This means that the system could sustain two or three arbitrary and simultaneous disruptions without a blackout or similar failure. These operating criteria are, not surprisingly, more expensive to satisfy than the N-1 criterion. A higher-order criterion is often used when high security is demanded or when recovery to N-1 reliability after a particular event would be particularly difficult—that is, if the N-1 event were to occur, returning the system to an N-1 secure state would be expensive or time consuming.

[4]Hospitals and other loads that are considered critical are often connected to the grid at multiple points, so they are nonradial. Even in these cases, however, instantly available dispersed generation is usually provided; most loads of this type have emergency generating units on their premises.

Interactions between Generation and Transmission for System Security

The role of generation/transmission interactions in determining a secure operating point is not always recognized in traditional operating environments. In particular, there is some substitutability between transmission and generation. For example, the system can at times make up for the outage of a generator by using another generator in the same control area, but at other times, by using a generator or generators elsewhere in the system if sufficient transmission capacity is available. The outage of any generator is initially felt everywhere in the system as a twofold impact. First, a downward frequency drift begins everywhere, and, second, the control area that contained the failed generator will start to see a large ACE. Frequency drift is stabilized initially because all generators and many loads are sensitive to frequency changes. The export (or import) from (into) a control area is by definition a regulated quantity. However, as a result of the loss of a generation and the fact that all generators participate in maintaining frequency, the immediate net effect on the area that lost the generator will be a reduction in its exports. Only after the area with the lost generator can readjust its remaining generators' output to accommodate for these reduced exports is the power that supplied was by the lost unit replaced with additional local generation (local reserves). Conversely, the loss of a transmission line will generally cause a redistribution of flows in the system. If the newly redistributed flows lead to overloads or other transmission system problems, a different generation pattern that is appropriate to the newly limited transmission conditions must be established.

Reliance on demand options during traditional system operations has generally been limited to certain interruptible load programs that meet reserve requirements when conditions are tight. Although in recent years there has been an increase in the use and creativity of voluntary customer load response programs, there remains much unexploited potential for using demand response to help manage system security. Some new trends in this area include the disclosure of real-time prices to loads, the more aggressive use of interruptible load programs in several regions, and the design of entire new ways of compensating customers for the willingness to be interrupted or curtailed. The emergence of alternatives to "all-or-nothing" power service is another possibility, e.g., allowing customers to sign up for guaranteed levels of service with anything beyond those levels subject to curtailment. Improvements in metering and metering technology will permit the system to take full advantage of voluntary load response. However, local regulatory barriers and some consumer groups' opposition to the notion that electricity should be treated as a commodity have resulted in some parts of the country being either forbidden or reluctant to adopt these demand response solutions.

System Losses

System losses must be taken into account in system operations. Most system losses are associated with series losses in the conductors; because conductors have resistance, every line, transformer, and generator loses some power as it delivers or transmits energy through them. There are also "shunt" losses in some cable systems and in overhead line arrangements, but these losses are generally far less important than series losses.

Consideration of system losses during operations is quite important for system efficiency. Average losses can account for two to five percent of total system energy, and, on the margin, losses can be considerably greater. Incremental losses in the ± six percent range are quite common, with incremental losses that exceed 10 and even 15 percent possible when there is significant reactive power flow. Ignoring losses or simplifying the accounting of them can lead to substantial economic inefficiencies as a result of some generators being chosen as "most economical" when in reality, as a result of their marginal losses at the time, they are far from economical. Likewise, desirable generators that do not increase (and in fact may reduce) losses may not be chosen because their marginal cost or bid may be slightly above some other less desirable generator. Thus, in almost all traditional system operations environments, some mechanism is used to account for losses.

Because losses vary significantly over the range of system operating capabilities, only correctly computed marginal losses should be used. A marginal loss refers to the change in losses due to the change in an injection of power at a given location. Marginal losses do not increase linearly with system demand, as some would like to assume. The best method for computing marginal losses during operations is based on the use of a transposed Jacobian matrix[5] of the system evaluated at the current operating point (Alvarado 1979). All that is required for this method is a good model of the system and a knowledge of the system's state.

An accurate way to incorporate marginal losses (used in many systems) is the use of carefully computed penalty factors. These factors are multipliers that are applied to the marginal cost (or bid) of every generator (and in principle also to every demand) to correct for the losses attributable to the power injection or the demand. A penalty factor of 1.1 applied to a generator at one location versus a penalty factor of 1 applied to another generator means that, under the postulated system conditions, 10 percent of the power injected by the first generator will be dissipated as losses and none of the power from the second generator will be lost. A penalty factor of 0.95 would indicate that for every MW injected at a location, a reduction of 0.05 MW in losses occurs, making this location desirable. In an efficient environment, credit is due to injections with penalty factors less than 1 although credit for loss reductions is not always given in traditional system operations.

An Optimal Power Flow (OPF) properly incorporates the consideration of losses, so a separate analysis of losses is not required when one relies on an OPF.

A word of caution is in order with regard to approximation of losses. In traditional systems, marginal losses have sometimes been computed by utilities based on "B coefficients," in which an approximate formula is established for the losses as a function of generation injections. Although such a formula can work reasonably well for some systems (particularly systems with known and established generation injection patterns), the results of such approximations can be quite wrong for systems with trading and unusual flow patterns or when conditions change. In many cases, using penalty factors obtained from B coefficients can be less accurate than using no penalty factors at all. Thus, the use of B coefficients is not recommended.

Competitive Operation: The Reliability-Driven Viewpoint

In the "reliability-driven" model of competitive market operation, trade is enabled by the posting of available capacities and requirements of the system for those engaged in commercial activities and the setting up of

[5]A matrix with the derivative of every system equation with respect to every system variable. It is used for many purposes, including efficient solution methods for the load-flow problem (Newton's method), and for accurate determination of incremental losses and power transfer distribution factors.

some form of reservation system to allocate and approve permissible trades. The operator retains the authority to perform administrative overrides of trades (including previously approved trades) when they impair system reliability.

Reliability and Unit Commitment

In a competitive environment, the problems of unit commitment and the necessity of having an appropriate available excess (reserve) generation can be resolved in a number of ways. Because of the time lags associated with the start-up and shutdown protocols for many generating units (and also the start-up and shutdown costs for these units), an appropriate organizational structure is needed for deciding what units should be in service ("committed") at a future time. The unit commitment problem can be addressed in various ways, from "command and control" measures (also called "administrative solutions") for ensuring reliability to purely market and contractual means for ensuring sufficient reliability. From an operations viewpoint, reliability depends on the units, loads, and transmission equipment that are available in real time, so it is impossible to entirely separate the problem of operations planning and unit commitment from the problem of providing reserves. Likewise, the ability to provide sufficient reserves or reserves from certain locations is entirely dependent on the ability of the transmission system to support the transfers that would be required under contingency conditions.

In order to assure an adequate level of reliability (including a sufficient number of in-service units) several choices (and combinations choices) are possible:

- Special contracts and/or rules can be put in place to designate certain units as "must run" (or "reliability must run"), allowing the system operator to require particular units to be available for security reasons under all or certain conditions. This type of "outside the market" rule is useful for addressing potential emergencies, unusual conditions, and possibly some market power situations when the number of choices available to an operator is otherwise limited.

- In some markets (the Pennsylvania-New Jersey-Maryland Interconnection or PJM, among others), generators may if they wish bid multi-step cost curves as well as startup and shut down costs into a centralized market, allowing the market maker to "take over" commitment decisions. This means that the bidder relies on the methods and algorithms of the central dispatcher to decide when to operate. Under these conditions, however, the solution chosen can change drastically with very small changes in either the bids or the parameters of the solution method used to choose the winning bids. There is a tendency for the method to, for example, identify and choose one particular solution that strongly favors one market participant and disfavors another based on what amount to trivial differences. Furthermore, once a particular participant has been "shut out" of the commitment, it may tend to continue to be shut out even though subsequent changes in system conditions would have clearly favored the participant at the onset (Johnson et al. 1997). In the systems of the past where both units were likely owned by the same owner, this made little difference, but, in a competitive environment, it invites disputes, and in the end there is no assurance that the path taken did indeed result in the lowest possible costs because changes in system conditions subsequent to the initial decision may have favored the path that was not chosen.

- A reserves market can be created in which generators can bid units into the market that will not necessarily be used to supply energy but rather will exclusively provide reserves. This forces these units to come on line (or have the capability to come on line sufficiently fast) in order to provide the contracted for reserves if these are offered into the market.

- Generators may self-commit generating units based on their own assessment of what real-time energy prices will be. In an extreme case, there would be no reserves markets and all self-commitment would be done in anticipation of real-time prices (including the anticipation of real-time price spikes). However, system operators would understandably be quite uneasy about such a design because the slightest insufficiency in supply would require a decision to, in effect, switch to an emergency mode of operation and curtail load. Thus, it is more likely that self-commitment would be based not only on the anticipation of real-time prices but also on prices that are paid explicitly for having a given amount of reserve available (i.e., a reserves market).

- Demand can be allowed to bid into the supply market so that the operator has demand control as needed, presumably at an agreed-upon price. There are various mechanisms for compensating demand for assisting with reliability. Offering uniform cheaper tariffs at all locations for the right to disconnect a load is one way. More appropriate designs are possible, including programs where users are paid per incident and location-specific tariffs and programs are created. To the extent possible, these programs should be voluntary and based on needs of the market rather than rigidly predesigned by states or regions.

- Demand can also provide reliability services in the form of voluntary interruptible contracts. In a few cases, these contracts have an option to permit the customer to "buy out" of the interruption, something that makes the reliability service less valuable.

Of particular interest is a "combination approach" that has been working quite successfully for PJM. This approach provides for self-scheduling but then uses a centralized commitment process to meet requirements not satisfied by self-scheduled units. This strategy helps mitigate the perceived problem of potential "unfairness" of centralized commitment (mentioned above) because a generator can self-schedule if it feels the commitment results are not economically consistent with the generator's expectations.

Administrative approaches to reliability management

The power system's physical requirements remain the same before and after restructuring: it must still be able to survive the outage of any component, it must still balance load and generation, and it must still maintain and manage voltage profiles and frequency. In a competitive environment, however, parties are free to engage in energy transactions, that is, to purchase power for delivery elsewhere in the grid. As part of this purchase process, it is necessary to secure the transmission network "rights" that will permit the transaction.

No transaction (or combination of transactions) is allowed to violate the system's security requirements. The "reliability-driven" viewpoint of grid operations presumes that markets are, for the most part, separate from reliability requirements. That is, it presumes that system operations do not interfere with markets until and unless there is a reliability problem, and, when a reliability problem occurs, the system operator has an overriding ability to intervene in the market with actions that include (but are not restricted to) the right to not approve, to disallow, or to terminate previously approved transactions. When this viewpoint is taken, the enforcement of system security limits (when and if required) is direct: transactions that cause the violation of a system constraint are not permitted, or, if a condition that warrants curtailment develops after a transaction has been authorized, the transaction is subsequently curtailed.

The scenario for congestion management in a competitive environment based on the reliability-driven viewpoint (and widely used within the Eastern Interconnection) goes more or less as follows:

- For every intended transaction, an Available Transfer Capability (ATC) on the transmission grid is determined. The process for determining what transmission capacity is available is based on rules created by NERC. These rules incorporate an initial determination of Total Transfer Capability, from which some “reserve transmission capacity” is deducted. Most regions within the Eastern Interconnection as well as WSCC have established and published protocols, based on NERC guidelines, by which this calculation is performed. For a comprehensive listing of these protocols, refer to www.wscc.com, to www.nerc.com, or to the various individual regional reliability council home pages. Because these rules depend on system characteristics and are administrative in nature, a process for continual updating and revision is required.

- The transfer capabilities are posted in an Open Access Same-Time Information System (OASIS) so that market participants can be aware of them. The system is updated as system conditions and scheduled transactions change. Currently, this posting of transfer capabilities is required by Federal Energy Regulatory Commission (FERC) order 889 and is available to all participants that wish to trade on the market. As described elsewhere, however, the notion of ATC without consideration of interactions among transfers and the impacts of transfer capacity on economics is of limited validity.

- Reservations for access for specific transactions are made and approved. Tariffs apply to the transmission capacity required by each transaction. Rights to transmission are reserved for designated period(s) at the desired “firmness level.” The transmission tariff is not coupled to system conditions but to an established access tariff for each transaction. Transmission tariffs are generally based on revenue requirements related to the investment costs associated with transmission. Transmission tariffs for open access are generally filed with and approved by FERC based on nondiscriminatory (“just and reasonable”) access principles, as required by FERC order 888.

- ATCs are updated regularly (typically at intervals of a few minutes) and re-posted in the OASIS as the scheduling of some transactions alters the ATC for other transactions. NERC requires that approvals of transactions reflect system capabilities and actual conditions. NERC does not, however, have the authority to truly enforce its requirements.

- Transactions that violate security rules are not authorized.

- During actual operation, the system is monitored for possible security violations. If security violations occur or become imminent and cannot be resolved by other means, a method for curtailment of transactions (called Transmission Loading Relief or TLR) goes into effect. The objective of TLR is to curtail (or threaten to curtail) transactions to relieve congestion and restore secure operating conditions. The determination of what transactions to curtail and by how much is based on formulas that take into consideration the size of each transaction and its relative impact on the congested flow(s). These formulas do not take into consideration the economics or the specific value of the congested transmission facility.

- As an alternative (or an extension) to TLR, anyone scheduling a transaction can also specify alternative dispatch that can be used to relieve a congestion condition in lieu of facing a TLR curtailment. This is called Market Redispatch (MRD). MRD resolves some but not all problems associated with the TLR approach to congestion management (NERC 1999).

TLR is only one example of an administrative solution to the problem of reliability assurance. Although we have chosen to focus on TLR as an example, other administrative solutions are possible and are used in other regions. However, it is a common feature of all administrative solutions that price and the actual value of transmission are not principal considerations in the process of reliability assurance, so these solutions share many of the features of the TLR process. Some other administrative alternatives are discussed below.

It is necessary to keep track not only of all transactions (this is done in NERC by means of a "tagging" system) but of the impact of every transaction on every potentially congested flow. This tracking is done in the NERC system by means of Power Transfer Distribution Factors (PTDFs), which track the unilateral impact of every system injection on every flow of interest with respect to a "reference location." PTDFs can be used to find the impact of every bilateral or multilateral transaction on every flow of interest. The tagging system is cumbersome and difficult to manage well, but some such system is necessary for administrative solutions to reliability management. The alternative to administrative reliability management that is embodied in nodal or flowgate pricing systems makes the tagging system mostly irrelevant. This alternative is discussed below.

As indicated above, TLR relies on a formula that curtails transactions based on several factors, such the impact of the transaction on the problematic flow, and the size and firmness of the transaction. The formula does not take economic factors into consideration. The formula used by for TLR curtailments is implied by the tabular curtailment procedure developed by NERC (available at www.nerc.com). This formula was made explicit in Rajaraman and Alvarado (1998).

The TLR formula and methodology are, in theory, fully capable of addressing any congestion problem in an effective manner. In practice, there are a number of problems with TLR, no matter how well implemented it is. From the reliability viewpoint, the problems of using the TLR paradigm for transmission congestion management are numerous and have been documented elsewhere (Rajaraman and Alvarado 1998). Some of the problems are:

- The TLR system can be "gamed" in a variety of ways, including overscheduling of transactions. Gaming has the potential of detracting from system reliability and does not contribute to the economic efficiency of the system.

- The curtailment process does not generally take into consideration desirable counterflows. It discourages putting together packaged multilateral transactions that would prevent congestion, simply because no credit is given for counterflows.

- The MRD method implemented by NERC allows market participants to avoid TLR transaction curtailments proposing pairs of generators that can be redispatched to relieve congestion in lieu of curtailing a trade. Even when MRD is used, it is hard to optimize system operation; when there is one congested facility, a single degree of freedom afforded by MRD may be sufficient, but when multiple facilities may congest simultaneously, a single MRD cannot resolve the problem optimally. Even for a single congested line, there is no assurance that the specific MRD offered for a given transaction will be optimal.

- Another issue with TLRs is their somewhat limited ability to control a transmission problem in view of the limited data that are used in the TLR analysis. For example, once a TLR is called, the mitigating effect it provides can be undone by the individual response of various system operators attempting to replace the energy that was being supplied by the TLR. In other words, the uncoordinated redispatch that is performed in response to a TLR can cause the same problem to repeat or a new problem to surface.

In spite of the many problems associated with TLR, it has been used with relative success to ensure secure operation of electrically interconnected but administratively and organizationally dissimilar systems. The most distinctive feature of TLR is its “command and control” flavor, which allows operators to deal with congestion in a reasonably effective manner irrespective of market considerations. Many “traditional” operators feel more comfortable with a system of command and control although many have come to realize that merely having the ability to command an action does not, by itself, ensure that the problem being addressed will be solved without creating other (perhaps worse) problems.

Another key point for any administrative solution is that, as a basic principle of efficiency, the model used by system operations ought to agree with the model used for the underlying market. TLRs or any other administrative solution violate this principle because the model used to curtail does not accurately reflect the manner in which the system operates, which creates gaming opportunities.

A well-designed and well-implemented transmission expansion plan should reduce the number and severity of TLR occurrences. There are, however, two problems with using TLRs as an indicator for assessing the adequacy of a particular transmission grid and the possible arguments for expansion of the grid:

- Care must be taken that a congestion problem is not simply “moved” to a different location. Consider the case of two transmission lines in series, 1 to 2 and 2 to 3, with capacities of 100 and 101 respectively. and no net load at location 2. Congestion can occur in the 1 to 2 segment, leading to the observation that, if congestion occurs frequently enough, a second parallel 100-MW line along the 1 to 2 corridor could alleviate the problem. More likely, however, this expansion would only move to the 2 to 3 segment the congestion that now takes place in the 1 to 2 segment of the line. The moral of this story is be careful where and how you expand the system or else you may spend a lot of money to simply move the problem somewhere else.

- The TLR system misprices the real value of congestion. For a radial system in which the value of power at one end of the line is $30 and the value of power at the other end is $70 and if the transmission tariff is $20, there will be a tendency to overschedule transactions because all participants will want to capitalize on the price difference. Conversely, if the prices were only $30 and $40, respectively, and the cost of moving power was $20, no transactions would take place even though there is value in scheduling transactions. The moral of this story is that before we can determine the value of a transmission expansion plan, it is important to have the prices right throughout the system. Prices can be set appropriately using a form of Locational Marginal Pricing (LMP).[6] A pure TLR system is not likely in practice to converge to optimal prices everywhere (even though this might be possible in theory).

Uninstructed deviations are another concern of traditional systems. In a reliability-driven system, the traditional “deferred payback” approach to uninstructed deviations can be implemented although it should be clear that it opens the door for intentional or unintentional abuse.

Competitive Operation: The Market-Driven Viewpoint

In the market-driven view of system operations, the operator makes relatively aggressive use of market signals and prices and uses markets as much as possible to assure reliability.

Nodal Spot Prices

In an ideal competitive market everything is, in theory, priced on the margin. In the electricity market, this principle should apply not only to generation but also to transmission. Reality is, of course, different from the ideal. To look at transmission from a market viewpoint, we begin by ignoring market power and assuming that every generator everywhere will bid its marginal cost into the market. We then proceed to define the nodal (spot) price of electricity at any system location as the cheapest way to deliver one MW of electricity to the location in question from among the available generating units while respecting all constraints and security limits in effect. If we define a nodal spot price this way, there can be no argument as to whether a different market structure could in principle lead to a cheaper set of prices: by definition, the nodal spot prices are the least expensive.

Spot prices can be attained in a variety of ways. The most direct is centralized calculation of prices by instantaneously and simultaneously “clearing” the market at all times and in all locations. This market clearing

[6]A methodology for pricing the energy at every node in the system at the cheapest possible marginal price of delivery consistent with available generation and with congestion conditions in effect. LMPs can be determined as by-products of an OPF although this is not the only way; knowledge of marginal unit locations (the location of the next cheapest generator in the system with available capacity to supply the load), congestion conditions in effect, and the characteristics of the transmission system are sufficient to determine the LMPs.

(not unlike the clearing process for markets such as the NASDAQ except that locational constraints must be respected in the transmission market) results in the establishment of (usually unique) prices for every node each time the market clears. (The technology is not yet at the point of permitting instantaneous real-time market clearing, but it is close.) Under this scheme, it is possible to define a system of property rights to the transmission system using financial contracts. The right to send power from one node to another can be acquired by buying a financial instrument, often referred to as a Financial Transmission Right (FTR) that is denominated in MW and entitles its holder to collect (or obligates its holder to pay) the difference between the prices at the two nodes. This financial right will exactly offset the deficit or gain resulting from selling the power at the injection point and repurchasing it at the withdrawal point at the respective nodal spot prices. In an idealized nodal market, in which generators have no market power and reveal their true marginal costs, an operator may have to do nothing to ensure security under most conditions.

The problem of determining nodal spot prices requires attention to a number of crucial details. First, there must be agreement by all parties about the system model that will be used to establish the prices. This model must be capable of producing unique, reproducible (auditable) results. Nonlinear models may be more "accurate," but they can lead to more than one solution, and this can be a serious problem. One way to avoid some difficulties of more accurate models is to use a simpler, slightly less accurate "linear" model. Linear models lead to reproducible prices. However, the underlying system model must take into consideration issues of voltage and reactive power flow if it is going to be credible. AC models are notorious for the fact that sometimes slight changes in the model can lead to important changes in the solution and thus to different price patterns. Thus, the best compromise is the use of linearized nonlinear models for all purposes of price determination.

For any given model the resulting nodal prices are sensitive to subjective security criteria determined by the dispatcher. When the dispatcher is also in charge of settling congestion, and paying off transmission rights whose value is determined by the nodal prices, the central calculation of prices puts the dispatcher (like PJM) in a monopoly position (Joskow and Tirole 2000). Being non-profit does not guarantee efficiency or equity and in the absence of market contestability to the dispatcher governance and monitoring of the dispatcher becomes an issue of concern.

There is always the possibility that the market will fail to clear and no set of valid resulting prices can be obtained. The only way in which this failure can be resolved is to permit much greater participation of the load. If all load is curtailable in principle, there will almost always be a valid solution for the system at zero generation and zero load. In addition, there is the issue of timing. Unless prices are determined and communicated promptly to participants, prices cannot steer the market to a reliable operating point. In short, there is no "perfect" way to establish prices. All we can hope for is reasonable approximations with good attributes and characteristics, as mentioned herein.

The nodal price patterns that result from the onset of congestion naturally create incentives to redispatch the system in a manner consistent with security. All that is needed in most cases is to produce the price signals sufficiently rapidly and then to patiently wait for the market to respond. In some cases, the market can respond based on the exercise of presubmitted inc/dec bids at individual locations. In other cases, it can respond as a result of independent action by generators observing a price signal. Only in cases where the market fails to respond because of either lack of clear price signals or insufficient available inc/dec capacity at critical locations does it become important to take "command and control" actions to direct the market. Experience with actual operation of this type of market (PJM and New York are two examples) has shown that, in spite of the current limitations on who sees the price signal (most loads do not) and in spite of "hourly averaging" effects (that is, prices tend to be for a whole hour period, even though in reality they should vary instantaneously as conditions change), markets that are purely nodal do in fact respond in a way that tends to ensure real-time security based almost entirely on price signals. An important caveat for such a system (particularly when spot prices are not correctly determined) is that, for short periods of time, prices may rise extremely high (prices reached $7,000 per MW in the midwest during the summer of 1998) because the market may fail to clear. This pricing situation prompted most systems throughout the U.S. to impose prices caps in some form or another.

Transmission Rights (Physical Rights, FTRs, FGRs)

In some cases, diversity in nodal prices can be traced to a relatively small number of constrained facilities. To the extent that the congestion status of these facilities is predictable, it is possible to directly set the price for their use at the corresponding shadow prices (the price associated with expanding the capacity of the facility by 1 MW) and define property rights associated with all potentially congested facilities, either singly or in combination, in terms of flow through these constrained facilities. Such a scheme can be implemented using a "physical rights" approach where the flows that a scheduled transaction produces through a constrained facility are determined according to the PTDFs, and the transaction must be backed by the appropriate portfolio of rights for accessing the congested facilities. In theory, it can be shown that the value of the FTRs should converge to the value of the portfolio of physical rights (also known as flowgate[7] rights, or FGRs) that are necessary to support a specific transaction under congestion conditions. A physical rights approach may require the acquisition of rights on many potentially congested paths, so a simplification is made requiring that only a predefined "commercially significant" subset of flowgates be addressed. Moreover, the exercise of physical rights requires much last-minute maneuvering to assure that rights are used and not lost, which adds to the complexities of system operation. In addition, many of the actions required by the physical rights may be in conflict with actions that the operator may wish to take in order to ensure real-time security; in other words, the physical rights approach to markets may be incompatible with the operator's need to control physical assets for security reasons.

Another approach to pricing transmission is based on flowgate rights (FGRs), in which parties acquire financial rights to specific flowgates. This approach represents a midway point between the physical rights and the FTR approaches. As in the case of physical rights, the acquisition of FGRs is based on distribution factors for flowgates that have been determined to be commercially significant. However, settlements are based on the actual marginal value of capacity on the flowgate at the time of congestion, i.e., the shadow prices on the constrained facilities. Under this setup, last-minute scheduling and operation are left to the operator, and all scheduled transactions are charged a transmission fee for the flows they induce on the congested facilities; this fee equals the corresponding shadow prices on these facilities. A transaction that is backed by the proper portfolio of FGRs will collect settlement revenues that will exactly offset its transmission fees. In practice,

[7]A flowgate is any line, transformer, or collection of lines and transformers where there is a restriction on the total power that may flow through. More generally, a flowgate is any system constraint.

however, a transaction would be covered by only a limited set of flowgate rights that only approximately track changing distribution factors, which would leave some residual congestion risk exposure unhedged. Such flexibility decouples operational decisions from the settlement issues associated with transmission rights.

Zonal Approximations

A fourth alternative for pricing in a real-time electricity market is to use zonal approximations. A zonal approximation is motivated by the intention to enable decentralized forward energy markets (that is, allowing market participants to freely trade with each other in the futures market without the need to involve transmission system considerations that require central coordination) by homogenizing the traded commodity (electric power) through deliberately ignoring transmission constraints within the zones. In cases where the only limits are on radial lines or where stability limits are translated into limits on the flow of the sum of power across several parallel lines, zonal approximations can be quite reasonable. Forward energy markets can result in infeasible schedules, so the operation of a zonal market requires that the operator have administrative tools available to force rescheduling of generators; these tools are generally presubmitted and accepted inc/dec bids for generator dispatch. In principle, if the operator has the authority to redispatch all the scheduled transactions and all generators are required to submit default inc and dec bids, then the operator retains full control capability when and if required.

The key issue is how the cost of redispatch is being covered. In some zonal markets, that cost is spread among all participants in a zone (in the form of an uplift charge levied on a load-share basis within the zone). This approach creates gaming opportunities that motivate some market participants to overschedule transactions in the zonal forward market and then be paid in the real-time adjustment market to essentially solve the congestion problem that they have created. This strategy results in a net profit when the cost of relieving the congestion is spread among all market participants. Unfortunately, such overscheduling is not only financially unfair to some participants, but it also creates serious problems for the operator who must anticipate the adjustment bids that it needs to procure. In any case, the problems attributed to the zonal approach are a result of the spreading of intrazonal congestion costs through uplift charges. To the extent that intrazonal constraints are rare and unpredictable, zonal aggregation in the forward market may have some merit in facilitating liquidity and forward energy trading. It is widely accepted that early commitments through forward trading and multi-settlements (that is, payments for forward contracts and payments for real time spot market transactions can be based on different prices that are locked in at the time that the transactions takes place) tend to mitigate market power by reducing the incentives of generators to manipulate spot prices. It is essential, however, that all transactions (forward and spot) be charged the correct ex-post congestion charges for the congestion they induce (either through a real-time nodal price mechanism or through flowgate fees on induced flows).

Can Pricing Alone Eliminate Transmission System Congestion?

A fundamental question about the relationship of markets and transmission system reliability is whether it is always possible to come up with a pricing pattern that, even within an ideal nodal pricing system, can eliminate congestion by means of pricing signals alone. The answer, partially provided in Glavitsch and Alvarado

(1998), is that this is not possible in every case. Although eliminating congestion by prices alone is possible in most cases, the lumpiness in the response capability of this type of pricing system when linear or roughly linear costs are the norm means that it is not possible to rely on price signals alone to relieve any possible congestion. Nevertheless, the system seems to work quite well in practice as evidenced by the successful real-time operation of PJM, where congestion is managed almost entirely by price signals alone. In fact, management of congestion by price signals alone can be quite effective (Ott 2000).

Under some conditions, it may be impossible to operate a system based on prices alone (particularly when demand is not exposed to or is unable to respond to the price signals). Thus, it is quite likely that a backstop would continue to be needed in such a system. The TLR approach can be viewed as a "command first, prices second" approach whereas the locational pricing approach can be better described as a "get the prices right first, then rely on command and control as a last resort." Even under the best pricing system, however, an administrative alternative (such as TLR) will continue to be necessary to ensure reliability in extreme cases.

The issue of market power is a bit more complex in this context. In a nodal pricing system it is simply not possible to study market power by observing locational price differences. A more complex analysis is necessary that takes into consideration the natural price differences that are the result of congestion and that does not ascribe these to market power. In other words, we cannot conclude *a-priori* that all price spikes are the result of the exercise of market power by some market participant. There are also potential interactions between market power in generation and ownership of financial transmission rights (FTRs or FGRs). A generator with market power in a so-called "load pocket" that imports power across congested transmission lines can profit from raising prices as long as the increased revenues exceed the lost sales. However, such a generator will have an incentive to raise prices even further if it also owns a large share of the transmission rights into the load pocket. By raising prices in the load pocket it can profit both from the sale of power in the load pocket and from the increase in the value of its transmission right that are based on the nodal price difference between the import node and export node.[8] Such a situation cannot, however, occur in the absence of physical generation ownership. Someone that owns solely financial rights or, more generally, pure financial positions, and has no control of assets in real time cannot have market power.

Other important considerations are the operational problems associated with day-ahead markets and activities. In most existing markets, there is a day-ahead market for energy. The rationale for having a multiple-settlement market (in this case day ahead and real time) is that clearing a market on a day-ahead basis is simple. Furthermore, there is an opportunity in this time frame for bidders to start and/or shut down generating units and time to arrange for transmission rights when necessary. However, when the day ahead market rules are not properly coordinated with those of the spot market participants may profit by gaming these discrepancies (for instance, by deliberately submitting incorrect schedules in the day-ahead market and deviating from them in the real time market). Such gaming may cause serious problems for the operator which must anticipate the deviations from schedules and procure sufficient reserves to maintain system reliability.

[8]This observation was made by Joskow and Tirole (2000). It has led in Texas to a restriction on the shares of transmission rights that any single market entity can own on any commercially significant constrained transmission line.

Impact of Congestion on Prices

As indicated above, in the absence of congestion (and losses), prices in a strictly nodal system are all identical. Although there may be (and in reality there always are) temporal variations in prices, there is no spatial variation in an uncongested, "lossless" market. Congestion, however, leads to differentiation of prices by location so that every node acquires, in effect, a unique and distinct price. The reason that prices are unique is simply that the PTDFs for every node with respect to a particular congested flow are unique. As an example of the price variations resulting from congestion, Figure 9 illustrates the congestion price pattern for the PJM system from 5 A.M. to 10 A.M. on October 13, 2001. For simplicity, zonal aggregate values are given rather than individual bus prices (individual prices are available from the PJM site at www.pjm.com). The purpose of this illustration is to emphasize that although they may seem somewhat "random," these prices are auditable and verifiable provided that the security criteria have been agreed upon. The prices are, however, sensitive to the implementation of the security criteria by the dispatcher. The fact that the dispatcher (PJM in this case) is nonprofit does not ensure efficiency or equity in the absence of market contestability to the dispatcher governance and monitoring structure.

Price signals give rise to behavior changes in real time. Observation at five-minute intervals of the prices and the supply at a few locations within PJM reveals the manner in which suppliers react to changing prices. The response observed depends greatly on the nature of the congestion and on the ability of the various generators on both sides of the congested facility to react in a timely manner.

Figure 9: Sample PJM locational prices for October 3, 2001, starting at 5:00 A.M. This table illustrates the rich variation in prices that is possible not only as a function of time but also as a function of location within the grid. Note: This table does not include nearly enough locations to be useful for operations and congestion management. A much larger number of locations is necessary to use pricing for efficient congestion management.

For the acronyms in this table, refer to the FERC website and report.

Region/node	5:00 A.M.	6:00 A.M.	7:00 A.M.	8:00 A.M.	9:00 A.M.	10:00 A.M.
PSEG	16.76	20.37	31.50	29.47	27.85	28.63
PECO	16.76	20.10	31.21	28.74	27.35	29.18
PPL	16.76	20.20	31.37	29.06	27.57	29.04
BGE	16.76	19.64	27.72	24.91	24.30	27.00
JCPL	16.76	20.30	31.50	29.35	27.78	28.82
PENELEC	16.76	26.58	48.13	54.91	47.36	26.90
METED	16.76	20.06	30.75	28.28	26.96	28.80
PEPCO	16.76	19.52	24.86	22.25	22.11	24.38
AECO	16.76	20.11	31.23	28.77	27.35	29.14
DPL	16.76	20.05	31.47	35.20	46.76	48.15
GPU	16.76	22.47	37.10	37.98	34.30	28.17
EASTERN HUB	16.76	20.08	31.61	36.39	50.57	51.71
WEST INT HUB	16.76	18.51	14.72	11.73	13.71	17.18
WESTERN HUB	16.76	20.67	26.34	25.63	24.59	22.33

Transmission System Expansion

Although in general transmission expansion in a pure market system will reduce congestion and improve reliability, there are quite notable exceptions. We illustrate just one: consider again a two-area system, as illustrated in Figure 10. Assume that prices are, as in most market systems, based on marginal costs of production. Under these conditions, one system (system A) sees low marginal costs and therefore low marginal prices. System B sees high marginal production costs and therefore high prices. The supply curve is, for purposes of this example, a three-tiered, steep-fronted curve. Expansion of the transmission system would lead to the possibility of trade between the systems, which would tend to equalize the prices on both sides. Assume that this equalization takes place at the "intermediate" price, as illustrated in Figure 11. The changes in consumer surplus are illustrated as the shaded areas in these two figures, which show that the decrease in consumer surplus is lower than the increase in consumer surplus for system A, leading to the seemingly counterintuitive conclusion that transmission expansion can, in fact, be counterproductive for consumers at large in a pure market situation. Although this would not normally be the situation, it is a cautionary example against assuming that transmission expansion is always beneficial. A similar example could be outlined which shows that expansion of the transmission grid can actually increase congestion.

Uninstructed deviations

Uninstructed deviations are the differences between intended or contracted amounts of energy delivery and actual deliveries. These occurs for a variety of reasons that include normal time delays in the response of units, metering and control errors as well as deliberate "price chasing" by generators who increase their out-

Figure 10: A two-area system with a proposed transmission expansion project. System A sees low prices, system B sees high prices, and a new line seems to make sense.

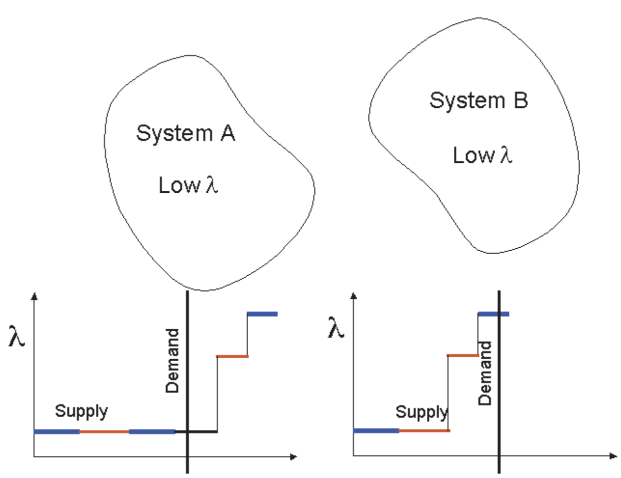
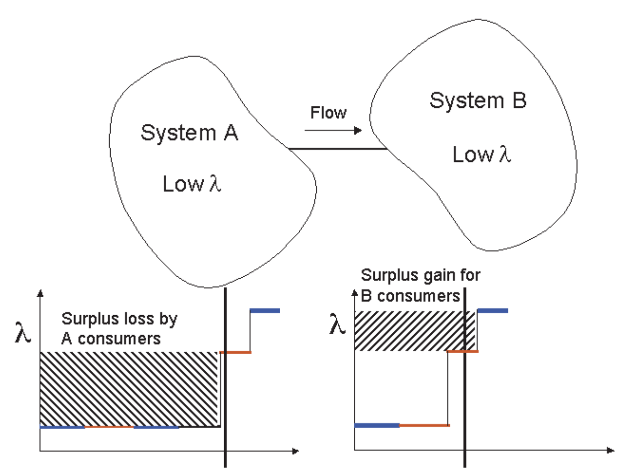


Figure 11: Construction of the line can result in a greater loss of consumer surplus than the resulting benefit to those consumers who benefit. The greater loss occurs in this case because there are fewer customers that benefit than those that see a price increase. This is not to say that surplus is not improved overall by the addition of the line, but that, in a market-pricing situation, there can be this unintended and important side-effect as viewed from the customers' vantage point.



put after learning that the price is high. In theory, in a market-driven approach to reliability and operations, uninstructed deviations can be addressed extremely simply, provided that a sufficiently robust and accurate metering system is in place. Such a system would price any uninstructed deviation at the market price for the given moment and location in which it occurs. Thus, any party having specified contracts for delivery (or consumption) of power could, in effect, hedge most of the intended amount by writing a contract with another party that specifies times and amounts for any desired price, with the understanding that settlement of any differences between contracted amounts and delivered amounts would take place on the locational real-time spot market. In effect, therefore, there would be no uninstructed deviations, only a real-time settlement market for the differences. You pay actual real time prices for any amount you have not contracted for. The reality, however, in all the currently operating markets is that real time prices are precalculated based on forecasted demand and supply bids and fixed for finite time periods (e.g., 15 minutes in Texas and 5 minutes at a subset of nodes in PJM). When the prices are announced at the beginning or prior to the time interval in which they apply (this is often justified on the ground of allowing time for load to respond), uninstructed deviations will occur and they require that the operator take mitigating actions such as dispatch of up or down regulation reserves in order to maintain frequency control.

Evolutionary Directions

The ideas and possible new directions in this section suggest what remains to be done regarding power system operations in a competitive market. In some cases, these ideas are not entirely developed, and in other cases they do not follow directly from the analysis in the previous sections.

Ensuring Reliability through Price Signals

As indicated above, one of the most effective trends in system operations has been the use of market price signals to operate the system. Using price signals and without the need for centralized controls, it is possible to induce behavior from generators (and loads) connected to the system based on the prices that the generators see at their respective locations. Instead of "commanding" that a particular generator produce more power, one can simply increase the price offered to that generator at that location at a given time. If the offer is above the marginal cost of the generator, the generator will naturally respond with an increased output. Likewise, to discourage production, the price can be lowered (to negative values if necessary) to encourage reduction in supply. Further progress in the direction of real-time node-specific pricing will go a long way toward ensuring power system reliability within the operational timeframe. To support this progress, FERC must "stay the course" of integrating the grid and unifying the rules to attain greater economic efficiency but should also recognize the need for more accurate system models whenever these models are to be used to set prices.

Ensuring Reliability by Connecting Transactions and their Flows

The second direction in which real-time reliability assurance is evolving is toward a more precise connection between transactions and flows (that is, an effort is under way to try to link or "tag" every transaction so that the flows that are "caused" by the transaction can be accounted for). The objective of this effort is to more closely focus command and control strategies on resolving specific problems. In addition, making command and control strategies more responsive to market signals (as is the case in Market Redispatch) is an important step for those cases where this strategy for security assurance is preferred.

Ensuring Reliability by Voluntary Load Response

Incorporation of load response is another important trend in reliability assurance. Load response can take many forms, ranging from alternative contractual arrangements between suppliers and load to real-time pricing at the retail level to new versions of interruptible load programs and other incentives. If an outage is seen as only a reliability problem when it is involuntary, much can be done toward improving load responsiveness. It is essential to enroll the creativity of the marketplace in the design of demand-response programs by enabling the types of customer/provider contracts that makes demand-response possible.

Ensuring Reliability through Improved Information on System Status

One of the most important preconditions for good system security is knowledge of the precise state of the system at any given time. Knowledge of system status is a precondition to establishing better flow and other types of system limits. It has become imperative to consider the evolution of a single seamless view of the system in real time. Concerns that the physical security of the system may be jeopardized because flow and other similar information is too widely available must be balanced against the security concerns that result when only partial, incomplete, and in some cases erroneous information is available about the state of the system. The creation of a single integrated view of the status of the entire interconnected grid will have great value for reliability assurance by giving those in charge a global picture of system status. More than one major blackout has been traced to operator actions based on a narrow view of the system and a focus on resolving a specific problem rather than a global view of system status and potential impact on the entire grid of the actions taken. Whether making information available to the marketplace in addition to the operators contributes or detracts from security is debatable. Recently, concerns about the physical security of the grid have suggested that publishing information about physical flows and system status represents a greater risk than would be associated with withholding such information. This view is not universally shared, however.

The complexity of determining system state increases significantly with system size. Some would argue that the growth of this complexity could be exponential, which would mean that determination of the state of the whole grid would be nearly impossible in practice. However, in the opinion of the authors (confirmed by Energy Management System experts), determining the system-wide state is possible. Nevertheless, to the best of our knowledge, no production-grade software is available to consolidate a regional SCADA system into a validated regional security model.

Ensuring Reliability through Grid Expansion and Energy Efficiency

Policies can be developed to support creation of excess capacity in the transmission grid to reduce regional market power, promote additional market activity, and increase reliability assurance. This intentional expansion of the grid by means other than reliance on the market can be encouraged either by specific policies for transmission expansion (for example, by direct or indirect government actions) or by the creation of "capacity markets" in transmission that can improve reliability margins and lead to construction of additional transmission facilities. These types of incentives for grid expansion are better explained in the companion paper, *Alternative Business Models for Transmission Investment and Operation,* by Oren, Alvarado and Gross.

Over time, energy efficiency may also be an effective tool for improving power system reliability by reducing total consumption and making any problem that occurs easier to solve.

Alternatives to Transmission System Expansion

All "outside the market" solutions (such as government- or quasi-government-sponsored expansion projects and taxes or subsidies to encourage expansion) should be considered in terms of their contribution to the "common good" of greater system security and simpler system operability. One must be careful, however, not to expand transmission in cases where expansion of generation would be more effective. This is particularly important when the best solution to physical security threats may be alternatives to transmission, such as distributed generation along with distributed fuel or energy-storage technologies.

It is also important to take into consideration the costs of fuel transportation (in recent years this refers mainly to gas pipelines) versus the cost of transmission system expansion. This tradeoff can only be taken into account accurately if the proper locational price signals are used for energy, with consideration given to transmission congestion. Only the "right" price signals will give rise to appropriate tradeoffs between the possible expansion of the transmission grid versus expansion of the fuel-supply system.

Intentional overexpansion of transmission for reliability and avoidance of market power should not be confused with the problem of free riders associated with transmission system expansion. The free rider problem (the fact that once a line is built, many parties who did not share the expense of construction will benefit from it) can lead to underexpansion of the grid. This is akin to the classic economics problem of the commons where an asset that has societal value (in this case the transmission network) will be utilized to the fullest extent by all parties, and any party investing in any improvement to the commons will be at a competitive disadvantage because it will bear the added burden of the cost of investment. This is a problem even in cases where economic expansion of the system can be justified. One of the primary purposes for the creation of Regional Transmission Organizations (RTOs) is to help resolve the free rider issue by creating mechanisms that will permit a wider view of the benefits of transmission expansion. Even prior to the creation of RTOs, the western states have adopted policies intended to take a more regional view of transmission and transmission expansion benefits. It is the role of the regulatory structure to deal effectively with the free rider problem so that otherwise economically desirable transmission system expansion takes place.

Concluding Remarks

The fact that "time and location matter" is fundamental to operations. There needs to be widespread recognition that the value of energy to an operator can have quite strong locational and temporal components associated with it. Thus, fixed tariffs do not reflect operational realities and are useless as a tool that can facilitate market-based operations.

All alternative methods for reliability assurance contemplated in this paper rely on a combination of incentives, load, and availability of resources. The resources are both transmission and generation. Reliability requires redundancy (that is, generation and transmission resources in excess of those necessary to satisfy the needs of an intact system). Providing reliability through generation alone may mean that a large amount of excess generation will be required, with a great deal of redundancy. The transmission system makes it possible to share generation resources in the provision of reliability. However, transmission redundancy is also required. A strong transmission grid is necessary for the practical sharing of reliability resources. Any expansion of the transmission grid to solve a problem may result instead in the problem moving to another location. Policies dealing with transmission system expansion must also address the lumpiness of transmission investment.

There are a number of options for transmission system expansion from the perspective of system operation and interconnection. All of these options present a possible system operations scenario followed by the related possible transmission expansion scenario.

- Option 1 (consolidated operations, market-driven government-incentivized transmission expansion): Establish a uniform criterion for system operation and interconnection, in consultation with parties who are knowledgeable about system operation. Establish uniform business practices that properly value transmission (much as FERC is doing at the moment—TLR and related approaches will not be sufficient). Although consolidation is called for, actual implementation of this model should use distinct coordinated regional control centers with protocols and policies appropriate to their regions. Base all decisions about transmission system expansion on a coordinated assessment of the anticipated benefits of expansion projects, but only after the pricing system has been given the opportunity to reflect the true costs of transmission and after generation options have been assessed. Encourage a sufficient voluntary demand response capability. Address all issues of system reliability by reliance on market forces up until the last minute, and rely on administrative solutions only under highly unusual or emergency circumstances.

- Option 2 (coordinated regional controls, government-directed transmission expansion): Operate the system much as it is operated now, retaining some form of control areas, but improve coordination. Use government incentives and resources to help create a "designed" expanded transmission infrastructure intended to relieve interregional bottlenecks. This approach must consider that, as a result, there will likely be regions where, under normal market operations, customers will see an increase in their electricity prices. Means for ensuring that proportionate benefits are derived by all parties (or at least that some parties are not adversely affected) should be part of the incentive system.

- Option 3 (government-assisted merchant transmission): Operation of the system takes place based on proper locational pricing, with single or coordinated set of distinct control centers, each with expanded demand-management options. Uniform business practices are required. The model for operations is to be based on the "market-driven" model described above in Section 4. Transmission expansion is primarily in the form of merchant lines. However, because of free-rider problems, governmental protocols are used to ensure that at least a fraction of the benefits that accrue (if any) are directed toward investors and not free riders.

- Option 3a: Same as option 3, but the model for operations is to be based on the "reliability-driven" model described above in Section 3 (e.g., a TLR model).

- Option 4: (utility-led government-assisted evolutionary alternative): Allow several operational and business models to coexist. Have the government operate reactively, approving and monitoring actions proposed by traditional industry participants and being proactive only in situations where a market power or major reliability issue becomes a concern. Otherwise, the government acts as a catalyst for action.

The authors' opinion, based on comments received as part of the DOE public-input process and the facts presented in this document, is that the most desirable method for system operation is Option 1: operate the grid as an integrated whole. Points that require further consideration are:

- Whether the grid should be organized into regions, RTOs, or some other structure, and

- Whether some form of control area should be retained.

Specific recommendations are:

- A unified business environment must be fostered for ensuring reliable operations, preferably based on the "market-driven" approach to congestion management. In order for market-driven approaches to reliability to be effective, they must be fast (i.e., operate in or close to real time) and have a sufficient number of nodes (or flowgates) available to permit correct "steering" of the system.

- Some form of administrative backstop to a purely market-driven approach must remain for extreme cases. When and how the administrative rules should "trump" the market is an issue that will require considerable additional discussion and investigation by knowledgeable parties that are sensitive to marketplace needs. In general, the answer to this question should be "only under highly unusual or emergency conditions" and not as a routine part of system operations.

- Voluntary demand management options to help achieve reliability should be expanded. The precise manner in which this can be done should not be prescribed; it should be driven by system needs and market opportunities, but the government can and should facilitate the consideration of these demand options to system operation and reliability.

- Transmission grid expansion should be based on the considered judgment of a non-partisan authority that addresses need from both the viewpoints of the operational characteristics of the system and the expanded trade opportunities the new transmission capacity will afford. Furthermore, the entity assessing expansion options must consider mitigation measures for the almost inevitable adverse impacts of increased interconnection on the customers in certain regions. Such mitigation should not render the market less efficient or more cumbersome to operate, however, but should be pursued by means of temporary financial structures (such as side-payments to adversely affected parties) that help spread the benefits of expansion.

- Study should be undertaken of drastically different transmission structures and organizations, including the possibilities of much greater use of HVDC transmission, greater system separation and islanding by means of DC converters, and active separation of the grid into separate areas. Because of their higher investment cost, these strategies should not be implemented unless studies clearly indicate their superiority for a particular situation.

- As a means of increasing operational accuracy leading to greater existing system utilization, methods should be used that permit the system to operate closer to its limits. Examples of these concepts include the use of dynamic line ratings; that is, where the flow limit of the line is not a precalculated number, but a value that depends on conditions such as the temperature of the line, its sag, wind conditions and more. Another example is the establishment and adjustment of stability limits based on actual operating conditions. This latter approach will require a continuing investment in methods and techniques for grid analysis and operation because such methods are not possible with today's state-of-the-art technology.

- Performance-based regulation (PBR) should be used to create incentives for transmission construction and efficient transmission operation and maintenance practices. Appropriate PBR methods should be developed in consultation with those who have experience with this type of regulation, both inside and outside of government. However, this topic is outside the purview of this issue paper.

- Study and enabling of a system-wide, real-time State Estimator should be undertaken, to provide information about the actual status of the system to both operators and market participants. Creation of this type of tool will require no new fundamental research but will require enlisting experts on large-scale computation and encouraging deliberate development and incorporation of new and expanded metering technology including sufficient metering redundancy, throughout the grid.

- Reserves markets should be made locational, ideally aligned with the main energy market, and nodal if necessary. This issue should be studied carefully before implementation.

- Incentives for technical engineering personnel must be compatible with the type of talent and capability that is required for grid operation and design. It is imperative that all limits and decisions relating to grid operations be compatible with sound engineering practices.

- System operators should remain independent and not be direct market participants. Nevertheless, some form of PBR should compensate and motivate system operators.

- Proper consideration of losses is essential. The correct way to handle losses is through use of penalty factors obtained from the system Jacobian matrix. Alternatively, an Optimum Power Flow can be used.

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Reliability Management and Oversight

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Introduction

Ensuring the reliability of the U.S. power system requires addressing both the system's physical characteristics and the commercial and regulatory frameworks within which it operates. Determining who sets reliability rules and how may be one of the most challenging aspects of maintaining reliability in an increasingly competitive electricity industry. The challenge arises because bulk-power reliability and commerce are tightly integrated; it is necessary for all involved (government policy makers, regulators, consumers, independent generators, and power marketers as well as the utilities that traditionally set and implemented the rules) to understand how bulk-power systems are planned and operated, under both normal and contingency[1] conditions, to participate effectively in commercial markets. And the reverse is true. One should not set reliability standards without understanding how they will affect markets.

The flow of power through the nation's electricity systems is governed by the laws of physics, so an action in one place on the transmission grid affects the entire grid. Thus, although combining individual utility systems into an integrated network increases reliability (by providing redundancy) and saves money (by permitting commerce among regions), interconnections also increase the potential for large-scale blackouts. Because the network is a community asset, its users must cooperate to ensure that it remains viable. And because large-scale blackouts are so onerous, common practice is to take extensive preventive action to assure that they do not occur. This prevention is usually successful, so the impact of reliability issues on the transmission system tends to be economic (i.e., commercial transactions are curtailed and/or power prices are

[1]A contingency is the sudden unexpected failure of a generator, a transmission line, or other piece of equipment connected to the electrical system.

raised in order to maintain reliability) rather than physical (power outages are usually localized and not widespread). Contingency reserves (generation or load that can respond rapidly to system-operator commands and extra transmission capacity that instantaneously accommodates the changed flow patterns) provide reliability by functioning as insurance against the sudden loss of a generator or transmission line.

Managing reliability raises important commercial and societal issues. Reliability rules can favor some commercial entities and exclude others, and these rules affect all of society because they affect electricity prices, electricity availability, and the environment (i.e., the locations of transmission facilities and the amounts, locations, and types of generation, which all have a role in assuring system reliability, have environmental impacts). All users of the power system have an interest in how reliable the system is, what the costs of reliability are, and how decisions concerning reliability are made. Deciding who participates in decisions concerning setting and implementing reliability standards and how consensus is reached involves considerations that range from broad policies regarding the overall level of desired reliability to specific rules governing what is required to participate in particular power system functions. Often the small group that decides specific details of system reliability rules determines the level of risk to which the overall community is subjected. Customers have some choice about the reliability of their electricity supplies—those who require greater reliability than the system provides can install additional equipment (uninterruptible power supplies or individual generators, for example) at their own expense to meet their specific needs. Customers may also have some limited ability to lower their electricity costs by agreeing to accept less reliable service (i.e., by buying interruptible power) or by selling reliability services back to the power system.

The North American bulk-power system is geographically vast, covering the lower 48 states, Canada, and parts of Mexico. It is also organizationally vast, encompassing a wide range of large and small public and private entities, generators, power marketers, transmission owners, transmission operators, and consumers. It must operate in real time within numerous physical constraints, and there are differences of opinion about how best to proceed given these constraints. Mechanisms are needed to make decisions and resolve disputes, which requires authority derived from some established source. This authority could be governmental—federal or state—or based on contractual arrangements.

One organization that has been suggested to administer reliability is the North American Electric Reliability Council (NERC), which is in the process of evolving from a bottom-up, industry-dominated, volunteer organization into the North American Electric Reliability Organization (NAERO), with an independent board. NAERO proposes to set and enforce mandatory standards with regional reliability councils that report to it (rather than vice versa). Regional reliability authorities have also been proposed; these authorities would be free to establish standards that focus on regional conditions.

The requirements of reliability management and oversight must be delineated in order to assess the extent to which alternative institutional structures can meet them. Federally derived authority is attractive because it would provide uniform coverage across the nation, so it would not require the negotiation of numerous parallel agreements.

In the remaining sections, this paper examines the following key issues related to transmission system reliability management and oversight:

- The historical approach to reliability in the U.S., i.e., the creation of control areas and interconnections and the formation of NERC.

- The unique features of the electric power system that affect reliability.
- Reliability from a risk perspective: who causes risk, who is exposed to it, and who pays for reliability.
- The need for and progress toward measuring, paying for, and enforcing reliability.
- Governance issues for new reliability organizations in a restructured electric utility industry.
- Actions that DOE, the Federal Energy Regulatory Commission (FERC), and others should take to improve the reliability of the bulk-power system and our key findings.

Background

Although we know when the lights are off, bulk-power system reliability cannot be easily or unambiguously defined. A reliable electricity system permits few outages or interruptions of service to customers; outages can be defined in terms of their number, frequency, duration, and the amount of load (or number of customers) affected. Equally important, but much more difficult to quantify, is the value of loss of load. A 10-minute power outage in a residence is an annoyance but usually imposes only small economic costs. A similar outage for a computer-chip manufacturer might entail the loss of millions of dollars of output.

Although generation and transmission failures cause only a small fraction of U.S. power outages, their economic and societal consequences can be much greater than those associated with distribution outages. Distribution outages account for the vast majority of customer outage events and outage time. Bulk-power outages, however, generally affect many more customers simultaneously and are much more difficult to recover from than distribution outages. For example, the bulk-power outages that occurred in the western U.S. during the summer of 1996 affected a much larger area and many more people than did the Chicago and New York distribution system outages during the summer of 1999.

The transmission system operator has two basic mechanisms to assure reliability: control of commerce and deployment of reserves.[2] When reliability is threatened, the first mechanism, control of commerce, redispatches generation away from the least-cost (in a traditional, vertically integrated utility) or free-market (in a restructured environment) pattern. This redispatch can be accomplished by means of a number of mechanisms, such as NERC's Transmission Loading Relief (TLR) protocols, reliability-must-run contracts, or locational marginal prices, and is the subject of the paper *Transmission System Operation and Interconnection* by Alvarado and Oren in this volume. The second approach for responding to reliability threats, deployment of reserves, is the primary subject of this paper. Reserves, which can be procured through markets, fit into the categories of extra generation, extra transmission, and load that is willing to curtail in the event of a sudden unexpected failure of generation or transmission.

[2]These two mechanisms are not completely independent. When reserves are acquired, they are taken out of commerce, raising the price of electricity.

Interconnections and Control Areas

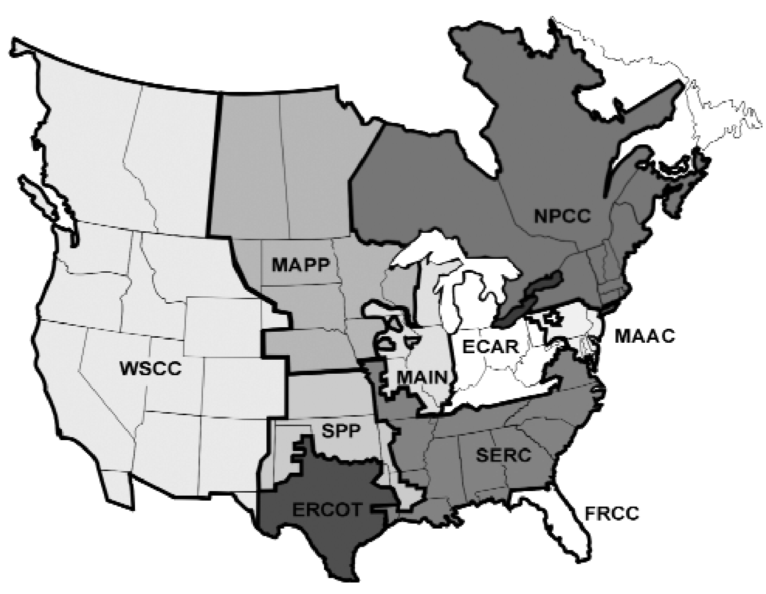
The North American electricity system is divided into three interconnections (Figure 1): the Eastern, the Western, and the Electric Reliability Council of Texas (ERCOT, which covers most of Texas). Within each interconnection, all the generators operate at the same frequency as essentially one machine; generators are connected to each other and to loads primarily by alternating current (AC) lines. The interconnections are connected to each other by a few direct current (DC) links. Because these DC connections are limited, the flows of electricity and trade are much greater within each interconnection than between interconnections.

The entity fundamentally responsible for maintaining bulk-power reliability is the control area. NERC defines a control area as: “An electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the Interconnection” (NERC 2001a). Control areas are linked to one another to form interconnections. Each control area seeks to minimize any adverse effect it might have on other control areas within the interconnection by (1) matching its schedules with those of other control areas (i.e., matching generation plus net incoming scheduled flows to loads) and (2) helping the interconnection to maintain frequency at its scheduled value (nominally 60 Hz).

Today approximately 150 control areas are operated primarily by utilities although a few are run by independent system operators (ISOs). Control areas vary enormously in size, with several managing less than 100 MW of generation and the Pennsylvania-New Jersey-Maryland Interconnection (PJM), California ISO, and ERCOT each managing about 50,000 MW of generation. Control areas are grouped into regional reliability councils, of which there are 10 in North America. These reliability regions, in turn, are part of the three interconnections.

The number of control areas and their sizes were set historically; each is the result of the specific manner in which its particular area developed. Although it is likely that there will be fewer and larger control areas in the future, determining the “correct” number and sizes of these areas relative to today’s electric power system is a complex combination of technical, political, and market considerations. When control areas are too small and too numerous, coordination among them is difficult. When a control area is too large, it is difficult for the system operator to manage. Unfortunately, some control areas view their autonomy as an economic advantage that they are reluctant to give up; some generators have also sought to

Figure 1: NERC’s 10 regional councils cover the 48 contiguous states, most of Canada, and a portion of Mexico.



become autonomous control areas for similar reasons. These attitudes draw attention to the need for true independence of system operators and clearly defined operating rules so that all parties have confidence that they are being treated fairly.

NERC

Historically, the vertically integrated utility industry utilized the North American Electric Reliability Council (NERC) a bottom-up, electric-utility-dominated, volunteer organization to establish reliability rules and monitor compliance. NERC was formed in 1968 in the aftermath of the 1965 Northeast Blackout and in response to the 1967 U.S. Federal Power Commission report on that blackout recommending the formation of an industry-based national reliability organization. NERC is funded by 10 regional councils, which adapt NERC rules to meet the needs of their regions. In 1994 the regional councils opened their membership to independent power producers, power marketers, and electricity brokers, and in 1996 NERC opened its board and committees to voting participation by independent power producers and power marketers (NERC 2001a). NERC and the regional councils have largely succeeded in maintaining a high degree of transmission-grid reliability throughout North America. However, the organization is dominated by representatives of the supply side (generation and transmission) even though the organization's purpose is insure the reliability of supply to the consumer. NERC replaced its 47-member combined stakeholder/independent board with a 10-member independent board in March, 2001. Members of the independent board are still selected by a stakeholder committee, however, rather than being appointed or elected through a political process as regulators typically are.[3]

Historically, the reliability councils have functioned without external enforcement powers and have depended on voluntary compliance with standards. NERC is now in the process of converting to a system of mandatory compliance under which violations will be subject to penalties (including fines). A pilot compliance program is underway to test proposed self-evaluation, data-reporting, and auditing procedures. In the absence of federal legislation requiring compliance with reliability standards, NERC has limited ability to enforce its reliability rules; in case federally derived authority is not forthcoming, NERC and the regional reliability councils are going forward with plans to enforce compliance through contracts and agreements.

Many Western Systems Coordinating Council (WSCC) members have voluntarily entered into contracts committing them to abide by WSCC reliability rules. WSCC is able to impose fines on these members if they fail to meet reliability standards. In this case, contract law, rather than federal regulatory authority, enforces reliability. The severity of sanctions increases with seriousness and number of infractions. However, this is a voluntary process, and not all WSCC members have agreed to these contractual obligations.

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[3]The NERC stakeholder committee has 35 voting members: one from each of the 10 regional councils, two from investor-owned utilities, two from state/municipal utilities, two from cooperative utilities, two from federal utilities/power marketing administrations, two from merchant generators, two from electricity marketers, two from large end-use customers, two from small end-use customers, two from transmission-dependent utilities, two from ISOs/RTOs, two from Canada at large, and one from Western Canada. There are also six non-voting government representatives: one from the U.S. government, one from each of the three Interconnections, one from the Canadian federal government and one from the Canadian provincial governments (NERC 2001b).

Until a few years ago, FERC and NERC operated on parallel tracks; FERC oversaw bulk-power commerce, NERC oversaw bulk-power reliability, and little interaction was needed between the two. Unbundling generation from transmission and creating competitive markets for electricity have dramatically changed this situation. The industry now recognizes that reliability and commerce are tightly integrated. Increasingly, FERC receives cases in which market participants complain that they face a competitive disadvantage because of NERC reliability rules, their implementation, or both. Partly to address these concerns, and recognizing the growing interaction between reliability and commerce, NERC established a Market Interface Committee as a complement to its long-standing Operating and Planning Committees in September of 1998.

In response to recent NERC requirements, Regional Security Coordinators address reliability issues within the reliability regions and across regional boundaries. These coordinators conduct day-ahead security analysis, analyze current-day operating conditions, and implement NERC's TLR procedures to mitigate transmission overloads.

Reliability Requirements

The electric power system is a communal resource. All users (generators and customers/loads) share the benefits of interconnected system operation. Reliability rules are required to assure that the activities of one user or control area do not adversely impact system reliability for other users or control areas.

Reliability rules require that control areas maintain a balance between generation and load and that they help maintain interconnection frequency. NERC's Control Performance Standards 1 and 2 (CPS 1 and 2) establish requirements for maintaining generation and load balance under normal conditions. The Disturbance Control Standard (DCS) requires that control areas re-establish the generation-to-load balance within 15 minutes of the unexpected failure of a generator or transmission line. NERC also requires voltages to be maintained throughout the power system under normal and contingency conditions. For this purpose, NERC requires that control areas have reserves (extra generation, extra transmission capacity, and/or responsive load) ready to respond immediately when the need arises. These reserves can be obtained through markets, but they must be responsive to system operator commands.

Unique Features of Electricity

Bulk-power systems are fundamentally different from other large infrastructure systems, such as air-traffic control centers, natural-gas pipelines, and long-distance telephone networks. Electric power systems have two unique characteristics:

- The need for continuous and near-instantaneous balancing of generation and load, consistent with transmission-network constraints: this requires metering, computing, telecommunications, and control equipment to monitor loads, generation, and the transmission system and to adjust generation output to match load.
- The primarily passive character of the transmission network, which has few "control valves" or "booster pumps" to regulate electric power flows on individual lines: control actions are

limited primarily to adjusting generation output and to opening and closing switches to remove transmission lines from or add them to service.

- These two unique characteristics have four consequences for system reliability, with practical implications that dominate power-system design and operations:
  - Every action can affect all other activities on the grid. Therefore, the operations of all bulk-power participants must be coordinated.
  - Cascading problems that increase in severity are extremely serious. Failure of a single element of the system can, if not managed properly, cause the subsequent rapid failure of many additional elements, disrupting the entire transmission system.
  - The need to be ready for the next contingency dominates the design and operation of bulk-power systems to a greater degree than do current conditions. It is usually not the present flow through a line or transformer that limits allowable power transfers but the flow that would occur if another element failed.
  - Because electricity flows at the speed of light, maintaining reliability often requires that actions be taken instantaneously (within fractions of a second), which necessitates automatic computing, communication, and control actions.

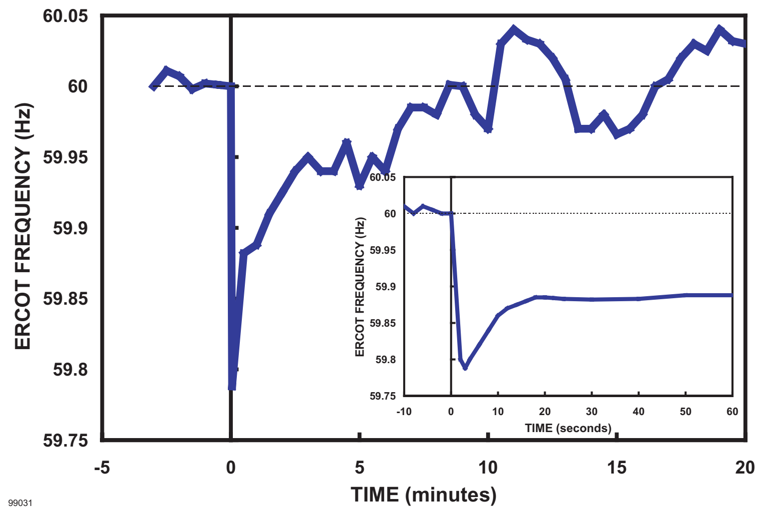
Reliability Functions

To maintain reliability, the system operator must continuously balance generation and load, maintain acceptable voltages throughout the system, and avoid overloading transmission lines and transformers.[4] Transmission line flows cannot, in most cases, be controlled directly, so line loads must be controlled by placing lines in and out of service and by determining which generators are allowed/required to operate in response to changing load patterns.[5] The interaction between reliability requirements and requirements that determine which generators can/must operate are primarily economic (they restrict transactions and raise prices as discussed by Alvarado and Oren, *Transmission System Operation and Interconnection* in this volume).

It is not sufficient, however, to operate the power system so that generation matches load, voltages are acceptable, and none of the transmission lines is overloaded at the present moment. The power system operator must also be concerned about contingencies—how the system will respond if a transmission line or a generator suddenly fails. Figure 2 illustrates how the electric power system operates when a major generating

[4]The power system is vulnerable to the overloading or sudden unexpected failure of any element of the transmission system. Transmission lines, transformers, circuit breakers, inductors, etc. are all of concern. The term "transmission line" in this discussion refers to all of these elements.
[5]Controlling loads is equally effective but generally harder to do.

Figure 2: Interconnection frequency before and after the loss of a 653-MW generator. The inset shows frequency for the first minute after the outage, and the larger figure shows frequency for the first 20 minutes after the outage.



unit suddenly fails.[6] Prior to an outage, system frequency is very close to its 60-Hz (cycles per second) reference value. Generally within a second after an outage occurs, frequency drops, in this example to 59.79 Hz. The frequency decline is arrested primarily because many electrical loads (such as motors) vary with system frequency and inherent generator response. Frequency is restored through a combination of autonomous (automatic) generator-governor responses and system-operator-directed responses from the generating units that provide contingency reserves. In the example in Figure 2, the system worked as it was intended to, and frequency was restored to its precontingency 60-Hz reference value within the required 15 minutes (at 8.5 minutes in this case).[7] Dedicated contingency reserves are required because there is insufficient time after a contingency to arrange for them. Similarly, there must be sufficient extra capacity available on transmission lines to accommodate the changed pattern of generation that results when contingency reserve generators instantly replace a failed generator. Additional transmission capacity alone may be adequate to accommodate unexpected failures of transmission lines. Alternatively, generation reserves that are closer to the load than the primary generation source can protect against transmission and generation failures.

The overall goal of reliability rules and procedures is to keep customers' lights on. Reliability can be divided into two basic elements: adequacy and security (the accompanying text box gives NERC's definitions for these two terms). Adequacy focuses primarily on assuring that there are sufficient generation and transmission resources available to serve the expected load. Security focuses on the ability of the power system itself to withstand inevitable contingencies. Both concepts involve planning and operations, but adequacy focuses more on planning to assure that enough resources are available, and security focuses more on operations that will permit the power system to remain viable even when unexpected events occur. It is difficult for operators to take actions that restore adequacy if insufficient generation has been built to serve the actual load. Conversely, an inadequate system can still be run securely if the system operator takes actions (which, unfortunately, may include intentional shedding of load) to ensure security.

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[6]ERCOT is deliberately used in this example because it is a small Interconnection, so frequency swings are more pronounced there than in the larger Interconnections. It would take an 8,000 MW drop in generation in the Eastern Interconnection to obtain the same frequency drop as in this example, and no generating units are that large. In this regard, larger interconnections are "better" than smaller ones because more generators are available to respond to emergencies; however, there also has to be enough transmission capacity to adequately couple the generators and to keep the system stable.

[7]At the time of this disturbance, NERC's allowable disturbance-recovery period was 10 minutes.

NERC's Definition of Reliability

NERC, the primary guardian of bulk-power reliability, was established in 1968. NERC's creation was a direct consequence of the 1965 blackout that left almost 30 million people in the northeastern United States and Ontario, Canada, without electricity.

NERC defines reliability as "the degree to which the performance of the elements of [the electrical] system results in power being delivered to consumers within accepted standards and in the amount desired." NERC's definition encompasses two concepts: adequacy and security. Adequacy is defined as "the ability of the system to supply the aggregate electric power and energy requirements of the consumers at all times."Security is defined as "the ability of the system to withstand sudden disturbances."

In plain language, "adequacy" implies that there are sufficient generation and transmission resources available to meet projected needs plus reserves for contingencies. "Security" implies that the system will remain intact even after outages or equipment failures.

Load as a Reliability Resource

The inherent responsiveness of loads to power system conditions and the system operator's (limited) ability to control loads both have important implications for reliability. Motor loads inherently reduce their power demand as system frequency falls, for example, helping to stabilize the power system when generation is lost. Similarly, heaters and incandescent lamps reduce their power consumption when voltage drops. This "natural" response has diminished in recent years as solid-state power-conditioning equipment compensates for changes in delivered power; for example, as voltage or frequency drops, load-controlling equipment increases the consumption of current to maintain the energy being delivered to the load. There are some benefits to solid-state load control, however. Some load control equipment is designed to disconnect loads to protect against damaging undervoltage. This response prevented a voltage collapse in a major U.S. city recently even though the response was uncoordinated and unplanned.

The system operator can also control how much load is served. Some loads respond to price signals; other loads may be directly under the operator's control (i.e., the customer has agreed to have load curtailed at the system operator's discretion). Load control, especially based on customer response to market signals, is an underutilized resource for helping ensure system reliability (Hirst and Kirby 2001a). Loads that respond to energy price signals tend to mitigate reliability problems because energy prices are often high when the power system is stressed and generation resources are scarce. Customers who defer energy consumption to time periods when prices are lower help themselves by reducing their energy costs, help other customers by reducing energy price spikes, and generally increase system reliability by improving the generation/load balance. Loads that specifically sell reliability reserves to the power system (currently a small number) are treated in the same fashion as generation reliability reserves; that is, they improve reliability by increasing the reserve supplies.

Operators also have the crude ability to "control" (disconnect) loads that have not agreed in advance to be curtailed. When the power system is under severe stress, the system operator's primary focus shifts from providing all loads with electric power to ensuring the system's viability. In the worst case, some loads become a resource whose primary function is to stabilize the power system. The system operator uses the only control over loads that is generally available: deliberately disconnecting blocks of loads. In this situation, system security is maintained at the expense of adequacy. Although this might at first appear to be a conflict in priorities, it is not. Serving loads safely, reliably, and economically is still the system's priority. Under these unusual conditions, however, load can best be served by securing system viability first and attending to loads second. This approach is preferable to the more difficult and lengthy process of restoring the power system after a major regional collapse, which disrupts service to all customers in the region. Curtailing service to a few customers to maintain the system's viability greatly reduces the total number of customers who are affected. Deliberate curtailments also generally leave customers without power for shorter periods than would be the case during a regional outage. Intentional curtailments can result from automatic relay action (under-frequency or under-voltage load shedding) during a disturbance. They can also result from system operator action, either preemptive—as with California's rolling blackouts in 2001—or in response to a disturbance.

Although load curtailment events are rare, they are important as the last line of defense before the power system collapses. Preparing for them requires considerable planning. Agreeing to the rules under which they are implemented requires consensus among technical, business, and regulatory interests. Rules governing how the system operator uses involuntary load curtailment should be publicly established and available.

Risk

Power system reliability management is risk management—a tradeoff between lower costs and greater reliability. The communal nature of the transmission system means that all users share the risk. The fundamental reliability management and oversight issues are determining what risks to take, when to take them, how much money to spend on risk mitigation, who pays for reliability, who is exposed to the remaining risks, and who decides on these matters. These questions are much more complex since restructuring than they were for the vertically integrated industry of the past. Finding satisfactory answers requires obtaining consensus among technical, business, and regulatory interests.[8]

The vertically integrated utilities of the past and their regulators implicitly agreed on the level of reliability to be maintained (and, therefore, on the amount of generation and transmission reserves that each utility carried). Greater flexibility existed for responding to changing risks. A system operator of a vertically integrated utility, for example, could decide to decrease dependence upon long transmission lines when a thunderstorm approached the service area by reducing remote generation and increasing generation close to the load. The increased cost of the off-economic dispatch was borne by all customers if the regulator approved of the practice. The key cost was the differential in production costs between cheap remote generators and expensive local generators. Customers saw this cost only as a slight increase in their average annual rates. Little analysis may have been required to justify this practice – and little analysis might have been possible because of the difficulty of precisely quantifying the change in outage probability or the cost of outages. Thus, implementation might have been left to the judgment of the system operator. This practice of altering

[8]This consensus must respect the laws of physics, but there are generally multiple ways to address any requirement, and technical concerns are not the only, nor necessarily the dominant, ones to address.

reliability rules based on the system operator's judgment and experience may not be permitted in the restructured industry, however. In particular, independent remote generators would object to their sales being curtailed. Impacts on remote generators are much greater than the simple production cost differential between remote and local generators; for independent generators, the difference is between running at a profit and siting idle at a loss. In addition, the remote generator might have to pay for the operation of the competing local generator if the remote generator had made a firm sale to local customers. Remote generators will insist on detailed analysis to demonstrate that the curtailment of their facilities was necessary, beneficial to the system, and done in a nondiscriminatory way. It is important for the system operator not only to be independent of commercial concerns but to be perceived as being independent. To the greatest extent possible, the system operator's decisions should be based on analysis rather than personal judgment. The analysis methods and results should be made public along with data concerning system performance.

The view from the customer's or load's perspective is somewhat different. It is primarily the loads that are vulnerable to the risk of system failures and blackouts. It is also the loads that pay the higher costs associated with greater reliability. In the future, customers may want to participate more directly and fully in the rule-making process, along with the traditional participants (generation and transmission companies).

Similarly, society as a whole and the governmental bodies that represent and protect it have an interest in power system reliability. While local power outages primarily affect customers in the immediate area, widespread outages have a disproportionately larger impact. Public safety is threatened. Police and fire departments can be overwhelmed with response calls. All commercial activity halts in the blacked-out region. These negative consequences of outages are the reason that the power industry has historically emphasized system security at the expense of reliability for individual customers even though the purpose of the power system is to deliver reliable power to customers.

Adequacy and Security

As noted above, adequacy focuses on ensuring, in the long term, that sufficient generation and transmission are planned, designed, built, and available to meet load requirements. Security addresses the short-term survival of the power system when disturbances occur. These two characteristics of reliability interact. A system with ample generation and transmission resources will be adequate and (if run well) secure because there will be sufficient resources to serve load and respond to contingencies. Adequacy, security, or both are reduced when there are not enough resources to serve all load requirements with sufficient additional reserves to address contingencies.

Adequacy can be maintained at the expense of security. That is, the power system can serve its full load without holding back reserves, but the resulting risk is that it would not survive a severe contingency. The risk period may be limited to those few hours per decade when loads are particularly high or when generation or transmission equipment is out for maintenance, or the risk may be much greater and more frequent if the system is seriously deficient in resources. Risk probability differs at different times as well, e.g., transmission line outages are much more likely during a thunderstorm than on a clear day.

Just as adequacy can be maintained at the expense of security, security can be maintained at the expense of adequacy. That is, load can be curtailed to maintain generation and transmission reserves that protect the system against contingencies. Load can be controlled by means of market mechanisms (responsive load programs) or through command-and-control mechanisms (rolling blackouts or underfrequency relays). Curtailments may be limited to small geographic areas or they may be system wide, depending on need. A curtailment may be necessary for only a few hours every decade or as often as daily.

All power systems balance adequacy and security in addressing reliability. It is not practical to build a power system that can withstand all contingencies or that will remain adequate under all circumstances. Because the system cannot be 100 percent reliable in practice, the important questions are who takes what risks when and who decides on the rules.

Risk Response

Contingency reserves and operating rules that govern their use are the primary mechanisms to mitigate risk. A brief look at the function of contingency reserves gives insight into how reserve rules have been established and may help to guide how reserve rules should be set in the future. Contingency reserves are resources that are kept out of service in anticipation of the sudden failure of a generator or transmission line. Their purpose is to address a probabilistic problem (the statistical event of a contingency occurring); however, contingency planning has been treated as essentially deterministic. That is, the NERC requirement for ensuring bulk-power-system reliability is deterministic in that it requires that the power system be continuously able to withstand any single contingency regardless of the probability of occurrence, the cost to protect against it, or the cost of failing to protect against it. Specifically, NERC requires all control areas to operate so that "instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency. Multiple outages of a credible nature shall also be examined and, when practical, the CONTROL AREAS shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from these multiple outages." (NERC 2001a)

There is a probabilistic nature to deciding which *multiple* contingencies are credible and should be considered; system planners and operators use an informal, deliberate, closed process to decide which contingencies are credible and which are not, and what types of events the system should be designed to survive. The loss of any single generator or line (the N-1 criterion), for example, is almost always considered. The simultaneous loss of both circuits in double-circuit configurations is also often considered. The simultaneous loss of multiple generators at a single generating plant may be considered if there are common-mode failures that can affect multiple generators.[9] Decisions about what to take into account are primarily based on the planners' and operators' experience with the power system rather than on detailed probabilistic calculations.

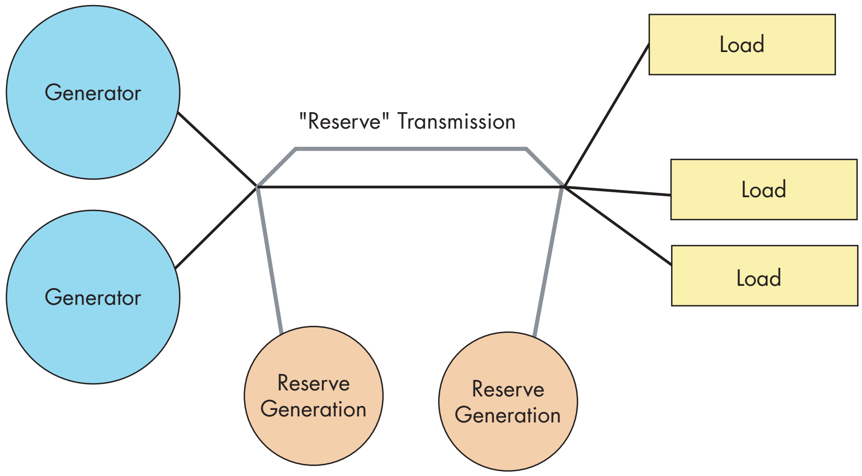
Once the process of deciding which contingencies merit the expense entailed in guarding against them and which contingencies are sufficiently unlikely that they do not, the process becomes more deterministic.

A simple example system

Figure 3 presents a simple isolated power system consisting of two generators supplying loads through a single transmission line. The reserve requirements are straightforward. The generator output and line flow are always equal to the total load. Contingency reserves equal to the current generator output are required con-

[9] A "common-mode" failure is a single event that could trigger what would otherwise be considered a multiple contingency. The failure of a common cooling water supply or a common fuel supply could cause the simultaneous failure of multiple generating units.

Figure 3: Contingency reserves compensate for the unexpected loss of generation or transmission in this isolated example system. Increasing the number of generators and reducing their individual size reduces the required generation contingency reserve.



tinuously. The contingency reserves can be made up of any combination of generation that is able to come on line quickly enough and load that can be removed quickly enough.

It might be rational to decide that the probability that both generators will fail at the same time is low enough that it is cost effective to provide only enough reserves to cover the loss of a single generator at a time. That decision would cut the reserve requirements in half (assuming the two generators are of equal size). The generators themselves can supply the reserve for each other. For example, each could be loaded to half capacity; the unloaded half capacity remains available as the reserve for the other generator. If there are 10 generators instead of two, it is easier to see the attractiveness of this option, with the reserve requirement being equal to the largest amount of load being carried by any one generator. Reserve requirements remain high (equal to the total generation rather than individual generating unit output), however, if transmission contingencies are also considered because both generators use the same transmission line. In any case, determination of the reserve requirements is a deterministic process once the credible contingencies have been selected.

The N-1 criteria appears straightforward in this case, though there are some complexities. Failure of either of the generators or the transmission line will affect all of the loads; reserves must protect against both contingencies. This requirement means that reserve generation must be located near the loads or a combination of remote reserve generation and reserve transmission must be maintained.[10] The reserve requirements now become deterministic. It does not matter whether the generator typically fails once an hour, once a week, or once a year. The reserve requirements remain the same until the probability of failure becomes low enough that the reserve requirement can be eliminated altogether. The failure rate may influence the choice of facili-

[10]For simplicity, the reserve transmission is shown as a separate line in the figure. Because it is not economic to directly control flows on individual AC transmission lines within a network, both the “primary” and “reserve” capacity would actually be on the same physical transmission lines. For example, two parallel lines could each be loaded to half of their individual capacities, or three parallel lines could each be loaded to two-thirds of their individual capacities.

ty that provides the reserves but does not affect the number of megawatts that must be maintained.[11] The amount of reserves required is equal to the amount of precontingency generation (ignoring changes in losses). If any less is maintained, the system collapses because post-contingency load will exceed generation.[12] Maintaining any more is a waste of resources.

Multiple versus single contingencies

The simple example above demonstrates how the probability of a single contingency does not affect contingency reserve requirements unless the contingency is so improbable that it can be ignored completely. Interestingly, multiple contingencies also exhibit a similar nonprobabilistic characteristic. If we greatly oversimplify to examine the underlying concept, we can assume a power system with 500 critical transmission lines in which the typical transmission line experiences an unscheduled outage once every 10 years. This means that the system operator faces about one contingency per week. The power system cannot be allowed to collapse on a weekly basis, so the system must be protected against single contingencies even though they each only occur once every 10 years.

The probability of multiple simultaneous contingencies is much lower. Assuming that a typical transmission outage lasts 0.1 hours (most are restored through automatic recloser action in a shorter time; others last longer, but the system operator takes corrective action within a fairly short time to reduce the system's vulnerability), the probability of a second line failure occurring while the first line is out of service, a double contingency, is reduced to one event in 35 years. In addition, many of these double contingencies will be sufficiently separated electrically so that they will not have compounding effects. Assuming that 25 percent of the double contingencies threaten system viability reduces the risk to one event every 140 years. This is an 7,008:1 ratio in the probability of a single versus a double contingency.

Although the simplifying assumptions and numbers in the example above have little relationship to reality, they illustrate an important point: the difference in probability of single versus multiple contingencies is so great that it may be reasonable to ignore multiple contingencies unless there is a common failure mode. This reasoning helps explain how power system planners and operators were able, when the industry was vertically integrated, to independently assess reserve requirements and reliability rules without needing extensive consultation with loads, generators, regulators and others.

Deliberate damage to the power system is an ever-increasing concern for utilities, law enforcement, policy makers, regulators, and the public. Increasing the attention paid to power system reliability in general will help reduce the system's vulnerability to terrorism. Deliberate attacks on the power system pose unique concerns, however, as addressed in the accompanying text box.

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[11]If the primary generator or transmission line fails infrequently, then the reserve generator should have a low capital cost but may have a high operating cost. If the primary supply fails once a week, it may be better to invest more in the contingency supply to lower operating costs.

[12]This is not strictly true. If the load is highly frequency sensitive, the system could settle to a stable lower frequency if "almost" enough reserves were available.

“Flexibility” in Reserve Requirements

The real world is not quite as straightforward as the simple systems in the example above where reserve requirements appear to be completely deterministic: either the system has enough reserves in the correct places to survive the contingency or it does not; if it does not, the system will collapse in a contingency.

The contingency reserve requirements outlined in the NERC and regional reliability council guidelines are similarly deterministic. Most regional councils establish contingency reserve requirements based on the size of the largest single contingency for the reserve-sharing group. WSCC requires contingency reserves equal to five percent of hydro generation and seven percent of thermal generation. Most require that at least half of the contingency reserve be spinning [NERC (2001a) defines spinning reserve as “unloaded generation that is synchronized and ready to serve additional demand”], but some only require that 25 percent of reserves be spinning (FRCC 1999). Which requirements are “best” and why? We were unable to find analysis documenting the reasons for the reserve requirements in any region. These analyses should be conducted, documented, and made public so they can be assessed by market participants and government regulators.

Determining what constitutes sufficient reserve is complicated by the networked nature of the transmission system, the difficulty of modeling the system exactly, and the dynamic interactions among multiple generators and

Deliberate Damage

The power system is designed and operated to withstand the unexpected failure of any single generator, transmission line, transformer, or other piece of equipment. It is also designed to withstand the simultaneous loss of multiple pieces of equipment if there are known physical reasons why they would fail simultaneously. Transmission lines that share transmission towers, for example, could fail simultaneously if a tower was damaged. This design philosophy provides solid protection against natural threats, such as lightning or falling trees. It also provides protection against some types of deliberate damage, e.g., an individual hunter shooting out transmission line insulators or someone toppling a transmission tower.

However, the power system is not typically designed to withstand the simultaneous failure of multiple pieces of equipment from either natural causes (e.g., hurricanes) or deliberate acts of sabotage. One reason that these types of contingencies are not guarded against is that the networked nature of AC power systems means that (a) it is quite expensive to protect against all multiple contingencies and (b) multiple contingencies are quite unlikely. Furthermore, the typical approach to protection—maintaining reserve transmission and generation capacity—is of limited use against a large-scale threat; a hurricane or saboteur is as likely to damage six transmission lines as to damage two. Determining which multiple contingencies to which the power system is currently vulnerable is technically complex and requires extensive system knowledge.

This means that the nature as well as the amount of protection is different when we consider the risk of deliberate damage. For example, reserve generation located closer to load is of more value in protecting against widespread damage to the transmission system than is additional transmission capacity. Determining what actions should be taken to protect the electric power system from deliberate threat is of great concern to DOE’s Critical Infrastructure Protection Program.

loads. All of these factors complicate predictions of post-contingency conditions. Moreover, during a contingency, additional support may be available from other sources or in other forms; for example, a control area can typically get reserve from the interconnection, and a system operator may have resources such as direct control of load shedding that can be manipulated rapidly to restore the generation-load balance. Together these factors make it very difficult to determine the exact reserve requirements that are appropriate for any instant in time.

If a system operator finds that load exceeds expectations and reserves are not available (or are extremely expensive), what can be done? The operator will curtail all nonfirm transactions and seek help from neighbors, etc., but when all options are exhausted and load plus reserve requirements exceed available generation capacity, what should the operator do then? One possibility is to curtail firm load (i.e., black out some customers) in order to preserve reserve margins and avoid risking a regional collapse. Politically, this is very difficult to do (in either the vertically integrated utility environment or in the restructured environment) because blackouts receive national attention. They point out that the system failed to prepare adequately for the events that led to the inadequate supply of energy and reserve, and they frequently prompt a phone call from the state governor to the system operator's chief executive. It is difficult to explain to the public that a system operator deliberately cut off power to customers because there was a chance that a generator or transmission line might fail and cause problems.

Because of the pressure to avoid loss of power to customers, there is a strong temptation to deal with inadequate reserves without curtailing firm load. System operators admit privately that they have commonly drawn down contingency reserves rather than curtail load. This concern is difficult to document in vertically integrated utilities because many of their operating procedures are not published. Industry restructuring and the establishment of ISOs have made reliability rules more specific and more public. The California ISO, for example, does not initiate rolling blackouts until operating reserves fall to 1.5 percent or less, which is well below the WSCC five- to seven-percent reserve requirements (California ISO 2001, WSCC 2001). Similarly, ISO New England provides for operations "which may result in degraded system reliability since the full operating reserve that is required for normal operation is not maintained" before the system operator resorts to intentional load curtailment (ISO New England 2001). Deferring the curtailment of load has consequences, however; it compromises reliability in neighboring control areas and throughout the interconnection.

Two Questions about Community Risk versus Individual Benefit

Two significant, distinct issues in power system contingency response are whether the danger of a regional collapse is increased by reliability decisions, and who pays and who benefits as a result of these decisions.

Reducing reserve margins to the extent that the power system is at increased risk of collapse (or taking any other action that increases the collective risk) has serious consequences for all users of the system and for society as a whole. The loads and society suffer the consequences if things turn out badly. Determining when the power system has moved from one level of risk to another is highly technical. Determining whether the power system should move from one level of risk to another is a commercial, political, and regulatory question that should be debated in a public forum.

Replacing conventional generation reserves with dependence on the interconnection, fast operator action, load response, or other similar strategies for responding to a contingency raises fewer societal concerns than reducing reserve margins, as long as these strategies successfully prevent a system collapse. These strategies raise commercial and regulatory issues for the individuals involved, however.

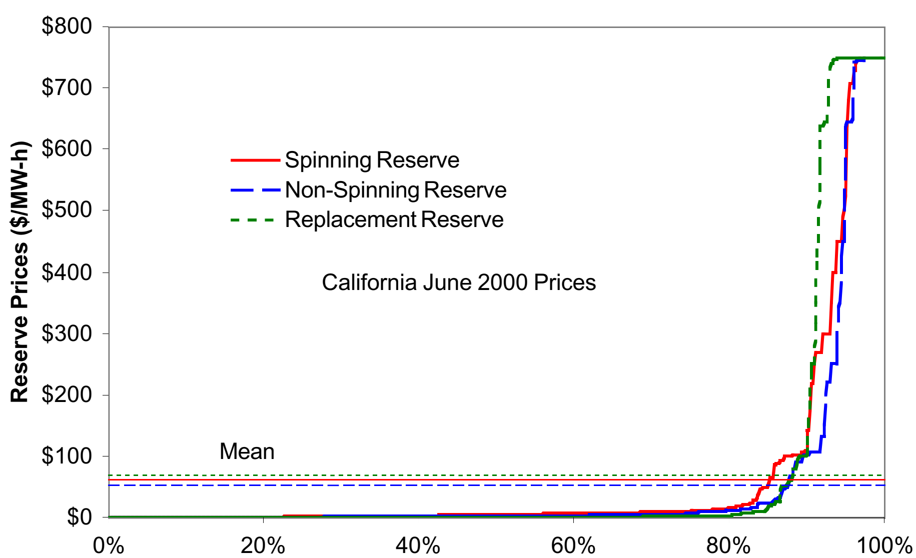
The communal nature of the transmission system means that risk to the system is generally assumed by the community at large. If an "incredible" contingency occurs or if contingency reserves are inadequate, then some or all of the system collapses. All of the loads (customers) connected to the collapsed portion suffer. For a large outage, additional societal costs (traffic, police, etc.) are borne by the affected region. Generators within the collapsed portion of the system and generators selling to loads in the collapsed portion suffer losses as well, but the loads suffer the most significant loss.

An individual control area that finds itself short of generation exposes neighboring control areas and loads to increased risk of system collapse if it uses its own reserves to serve load. It is implicitly relying on reserves in other areas as backup but without paying the other areas for this "service." In a restructured electricity industry, each commercial entity is responsible for contracting for an adequate energy supply. If a load fails to contract for enough supply or if the supply fails to deliver, then using contingency reserves to cover the shortfall simply rewards the poor performer and exposes good performers to added risk. Because the poor performer likely saves money by means of this behavior, it has incentive to repeat its poor performance.

Risk and Price

Historically, some system operators operated (at least occasionally) with reduced reserves when reserves were simply not available. In the restructured environment, should the operator's choice about how much reserves to procure be affected by the price of those reserves? Contingency reserve prices vary dramatically, as shown in Figure 4. Although the price of spinning reserves was typically quite low in June, 2000 (the median price was only $5/MWh), it reached its $750/MWh cap two percent of the time and was above $100/MWh 12 percent of the time. The spinning reserve price was below $15/MWh 80 percent of the time. These statistics indicate that there were many hours during which reserves could have been increased at relatively little cost and a few hours during which reserves could have been decreased in return for relatively large savings.

Figure 4: Contingency reserve prices in California are typically low with occasional price spikes.



The probabilistic nature of contingency reserves argues for adjusting the amount procured based on the price. Deciding which contingencies are credible and must be protected against is basically a probabilistic economic tradeoff.[13] That is, we don't protect against contingencies that are too unlikely and/or whose consequences are very low cost. Said another way, we stop protecting against contingencies when the cost of the protection exceeds the benefit of avoiding the contingency. Unfortunately, it is difficult to rigorously analyze this economic tradeoff. Useful data on contingency probabilities and the costs of the contingencies (the value of lost load) are not available.

It is also difficult to unambiguously value load that is lost when the system operator curtails load either preemptively with rotating blackouts or during a contingency. This load shedding is involuntary for the loads affected but voluntary for the system in that the system operator deliberately uses load to restore or instead of generation reserves. An “advantage” to the system and the loads that are not curtailed is that the loads that are involuntarily shed are generally not compensated. Compensating curtailed loads would reduce the economic incentive to push the cost of involuntary load interruptions onto certain loads chosen by the system operator.

An improved system would be to establish a market-based program for loads to voluntarily offer, for a price, to immediately curtail in the event of a contingency. Such a program would formally recognize voluntary load response as a legitimate contingency reserve. Technology would have to ensure that the response was as fast and accurate as that offered by generators. It is important to note that this use of load as a contingency reserve resource does not change the system’s reserve response; it only reduces the need for generation to supply that reserve. ISOs expanded their emergency and economic demand-response programs in 2000 and again in 2001 as an initial step in this direction.

New risks: common-mode failure, gas, trading hubs, and time

Making the amount of reserves carried by the system price-sensitive introduces a potential common-mode failure. In interconnections with multiple reserve-sharing groups, each group is individually responsible for its own reserve requirements. Because frequency is common throughout the interconnection, however, the groups support each other in the event of a major contingency. If one group has underestimated its reserve needs or if its reserves fail to respond adequately, that deficiency will likely be made up by another group. Tying the amount of reserves available to reserve prices will mean that all groups will tend to procure fewer reserves when prices are high, increasing the system’s vulnerability to collapse.

Natural gas is an attractive fuel for producing electric power, especially for new generators. The capital costs for gas-fired generating plants are lower than those for coal-fired plants. Natural gas emissions are also inherently lower, so environmental mitigation costs are reduced relative to those for coal plants. Gas-fired plants can be built much more rapidly, often within two years versus seven to 15 years for coal-fired plants. There are often fewer siting problems for gas plants as well. The higher cost of gas is one of the few disadvantages. Gas-fired plants also have reliability benefits. They are typically faster to start and to respond to load-change commands than coal plants. This increases their value in providing contingency reserves. But gas-fired plants also raise reliability concerns primarily related to the inability to store gas. In contrast to coal-fired power

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[13]ISO New England staff members indicate that the inability to quantify the costs and benefits of contingency protection has stalled efforts in New England to formalize reserve-price response.

plants, which in the past typically had 30- to 60-day fuel inventories on site, a gas shortage hits all plants quickly.[14] Worse, gas-fired generators fed from the same gas pipeline are tightly coupled. Failure of a single gas pipeline may constitute a region's single worst contingency. For example, consider the situation in Arizona where approval has been given for the siting of 12,000 MW of generation, all of which would be served from the same pipeline (this is almost 10 percent of the current WSCC capacity) (Smith 2001).

Trading hubs may present a similar problem. If developers of new generation find it economically attractive to locate close to trading hubs, the resulting increased concentration of generation will result in multiple generators depending on the same transmission path even if the generators themselves are sufficiently independent to have no common-mode failures. An example of such a trading hub is Palo Verde, Arizona where a large number of generators are requesting interconnection.

The long life and high cost of power system equipment present challenges to reliability in a competitive industry. Large transformers, for example, can operate for 40 years or more, but their longevity is tied to how they are operated. Heat (overloading) is a major contributor to insulation degradation and equipment failure although this effect is difficult to quantify as it takes place over time. This fact makes it extremely difficult to put a price on an emergency response action by a competitive generator (or, potentially, a competitive transmission provider) because, although temporarily overloading a piece of equipment may shorten its life by some amount of time, its failure is not likely to be immediate. How should a competitive supplier factor in the impact on equipment when pricing emergency response? And how can a system operator know what a reasonable price is? If the equipment owner does not feel that it is being compensated for its risk (either through overall price or payment for the event), it may not respond to reliability events.

Decision making and risk taking

Decisions about procuring contingency reserves are made by power system planners and operators, but customers, and, to some extent, generators, face the resulting risks. This split between the decision maker and the risk taker was the same when utilities were vertically integrated, but the consequences were not as dramatic because the system operator typically also owned the generation, and the transmission and often the distribution systems, and regulators could hold the company responsible for its overall performance in supplying energy to customers. Although FERC and state regulators will continue to oversee system operations, transmission, and distribution in the restructured environment, the responsibility for overall performance of energy delivery is now split among generators, system operators, transmission owners, etc. However, the customer still pays the consequences of unreliable energy supply. Customers should therefore be involved in determining the amount of risk to which they want to be exposed and how much money they are willing to pay to avoid the risk of widespread blackouts.

With a properly structured market each customer can, to some extent, decide individually what level of reliability s/he is willing to pay for. A customer can select interruptible power if price is more important than reliability, for example, or a customer might decide to sell reserves to the power system if the price is attractive, if it can respond fast enough, and if the reserve supply rules are technology neutral. In a fully functional future energy market, adequacy may be the responsibility of each supplier. If a supplier fails to provide ade-

14Competitive pressures are pushing coal-fired generators to reduce their coal inventories as well. Some generators now maintain inventory of 10 days or fewer.

quate resources and if it cannot obtain them from the market, then that supplier's customers would be curtailed. The market would apply appropriate pressure on suppliers to maintain adequacy.

It is equally important that all parties (loads, generators, regulators, transmission owners, and system operators) be involved in the communal decisions that determine the level of security that the system should maintain.

Measuring Reliability Response

Generator response to system operator commands during contingencies continues to be an area of major uncertainty that is intensified with restructuring. In the vertically integrated utility environment, the system operator that was responsible for reliability belonged to the same corporate entity that owned the generation that provided contingency reserves. Measuring generators' response to contingency orders might have been useful for the internal operations of the utility, but it was not critical for judging the overall performance of the system. Restructuring has separated the system operator from the generation resources and thus created a great need for metrics to assess performance (Hirst and Kirby 2001b). Without metrics, it is difficult to know whether a generator is providing the reserve service that it is obligated to provide. Unfortunately, metrics have not been established in most regions to effectively gauge performance when contingency reserves are called upon. NERC started to develop a policy (Policy 10) on Interconnected Operations Services (essentially FERC's ancillary services), but this effort has stalled, and the policy remains only a reference document. It is likely that performance will deteriorate in the future if there are no clear service definitions and metrics on which to base compensation and nonperformance penalties. Some of the contracts that independent power producers (IPPs) and transmission service providers (TSPs) signed when IPPs bought existing generating units failed to take account of some "ancillary services" that were still needed to support the system, such as reactive supply and voltage control. Because IPPs have no way to get paid for these services in the absence of contracts that address these issues, some producers are reportedly balking at providing the services. Creating markets for reliability services would establish a means for compensating service providers.

WSCC has implemented a Reliability Criteria Agreement to enforce reliability requirements in a restructured environment (WSCC 2001). This agreement parallels NERC's Pilot Compliance Program, but WSCC's contracts with its members allow for enforcement. WSCC assesses compliance based on five criteria for control area operators:

- Operating Reserves—each control area is required to maintain regulating and contingency reserves (spinning and nonspinning).
- Disturbance Control—each control area is required to successfully respond to each contingency (restore area control error within 15 minutes).
- Control Performance Standards 1 and 2—each control area is required to meet NERC control performance standards (limits on area control error under normal conditions).
- Operating Transfer Capability —each control area is required to keep flows over transfer

paths (transmission lines) within the Operating Transfer Capability (OTC) Limits of each transfer path. Stability, thermal, and/or voltage constraints set OTC limits.

WSCC also enforces compliance for generators based on continuous operation of the generator's power system stabilizer and automatic voltage regulator. These criteria are concerned with whether generators are maintaining their fast-response capability to maintain power system stability.

Note that the first criterion above (operating reserves) ensures that the control area continuously maintains the required reserves. The second criterion (disturbance control) addresses whether the reserves actually respond effectively when contingencies occur. The third and fourth criteria (control performance standards 1 and 2) assess whether reserves respond effectively during normal operations. The fifth criterion (operating transfer capability) focuses on whether transmission reserves are continuously maintained.

Penalties for violating reliability criteria range from a letter sent to the violator's chief executive (for an initial violation at a relatively low level) to fines of $10,000 or $10/MW, whichever is higher (for multiple violations at higher levels). Levels are determined by the amount of shortfall relative to the criteria. Allowing operating reserves to dip to between 90 and 100 percent once during a month earns the control area operator a letter to its chief executive. Allowing this shortfall twice during a month or dropping between 80 and 90 percent once in a month typically results in letters to the chief executive and the chairman of the board of the offending party, the state or provincial regulatory agency, FERC, and the U.S. Department of Energy (DOE). Allowing operating reserves to drop to between 70 and 80 percent or repeating earlier infractions starts to cost the control area $1,000 or $1 per MW of shortfall, whichever is greater. Dropping below 70 percent or continuing to repeat earlier transgressions increases the financial penalty.

The penalties for violating the other reliability criteria are identical although the metrics are specific to each criterion. The exception is violations of the disturbance control criteria; the penalty for these violations is an increased contingency reserve criterion for the subsequent three months.

Experience to date is not conclusive regarding the effectiveness of the WSCC Reliability Management System (RMS) system in improving performance. To date, $2.2M in sanctions have been assessed against participants in the RMS program and $0.3M against non-participants (not all WSCC members currently participate in the program) (Dintelman 2001). Performance in some categories (maintaining automatic voltage regulators, for example) seems to be improving for participants but not for nonparticipants, which might be an indicator that the program is effective. However, compliance with the DCS appears to be improving for both participants and nonparticipants while the number of noncompliance incidents for all RMS categories appears to be growing for both groups as well.

None of the systems or proposals that we examined linked the penalty for a control area's or a reserve supplier's nonperformance to the cost consequences. As was true in the past, loads that are curtailed, either proactively by the system operator to manage a contingency or as a direct result of the contingency, are not compensated for their losses. Similarly, no attempt is made to quantify and compensate for societal damages (police and fire response, etc.) that result from a widespread outage.

Perhaps worse, data concerning the number of customers subjected to power failures or unacceptable power quality, the time taken to restore power, and the amount of power not delivered are not publicly available.

This makes it impossible to know whether reliability is improving or declining and to what degree. (These data are commonly available in the United Kingdom and much of Europe.)

Governance

As discussed above, the utility technical community (through the NERC committee structure) historically set reliability management rules. NERC was "owned" by the regional reliability councils which, in turn, were "owned" by the member utilities. This structure is beginning to change as NERC and the regional councils open their membership and boards to nonutility participation. Still, staff from transmission and generation entities dominate the committee structures.[15] Although this imbalance in representation may make sense from a technical standpoint, it leaves customers with little ability to influence the reliability decisions with whose consequences they must live.

The question of governance and independence is problematic for all organizations that attempt to be neutral facilitators. The California ISO, for example, has been criticized for not being sufficiently independent. The *Energy Daily* (Davis, 2001) raises questions about the ISO's dealings with the states in its attempts to obtain sufficient power at reasonable cost for consumers:

> The ISO, critics charge, is far from independent, and its actions could stretch beyond providing information to DWR [the California Department of Water Resources] and include manipulating power prices to prevent the [California] governor from being embarrassed by a huge gap between market prices and prices in the long-term contracts signed earlier this year.

The authority behind reliability rules is also problematic. Because NERC is a voluntary industry organization, it has no enforcement power. For many years, its reliability rules were little more than best practices or guidelines. The real authority came from state regulators who had power over individual utilities. State regulators and FERC tended to defer to NERC on technical matters, so a utility that abided by NERC rules was generally regarded by regulators as behaving prudently. To date, only WSCC has found an alternative method, voluntarily entered binding contracts, to establish reliability authority. NERC and the regional reliability councils are proceeding with plans to enforce compliance with reliability rules through contractual agreements in case congressional action and federally derived authority are not forthcoming.

With the increased commercial activity brought about by restructuring, there is a great need for clearly defined operating and planning rules. The commercial separation of generation from system operations, and of one generator from another, makes for a healthy competitive environment but one in which everyone is

[15]Although NERC has made an effort to open the committee structure, the NERC Roster reveals continued dominance by generation and transmission entities (NERC 2001b). The Operating Committee, for example, has 33 members of which 22 work for public, private, state, and federal utilities, five work for independent system operators, two represent IPPs, two represent power marketers, and two represent customer groups. The Interconnected Operations Services Subcommittee, which is tasked with developing Policy 10 on ancillary services, has 20 members of which 15 work for utilities, two work for independent system operators, two work for power marketers, none represent loads or regulatory interests. These are typical examples.

abiding by the letter of the law rather than the spirit. This atmosphere creates a need for clear, consistent, rational, and enforceable rules. Penalties for violations should be tied to the cost consequences for those who suffer damage or loss as a result of the violations. The atmosphere also calls for an open rule-making process that it technically competent and especially sensitive to the desires of the groups that bear the economic and physical costs of reliability rules. Past standards were not accompanied by technical or economic analysis and justification. In the future it will be necessary to make public the analyses that justify standards on both engineering and economic grounds. Data must also be publicly available so that reliability performance can be judged and all parties can determine whether their needs are being met effectively. The rule-making process should include participation, at the board and the technical committee levels, by system operators, loads (customers), generation and transmission owners and operators, and the public.

The public interest will differ from the load's/customer's interest at times. There may be a distinct public interest in maintaining civil order, which would make avoiding geographically large outages especially important. Avoiding such outages would favor the practice of sacrificing individual loads in order to maintain overall system reliability. Promoting economic growth is another public interest that has reliability implications. Industrial loads that require reliable power also create jobs. Concerns over endangered salmon in the Pacific Northwest provide a different example where power reliability concerns conflict with a public interests concerning endangered fish. The Bonneville Power Administration declared a power emergency and reduced fish spills (water releases through dams to help salmon fingerlings swim safely to the ocean) in the spring of 2001 based on a forecast of power deficits for the following winter. The deficit forecast was in turn based partially on reliability standards for loss-of-load and reserve requirements. These reliability standards are not formally or publicly developed, however. The Northwest Power Planning Council, which is charged with ensuring a reliable power supply for the region while also protecting the environment, is encouraging the region to formally agree on reliability standards to help in the public process of balancing energy and environmental needs (Fazio 2001).

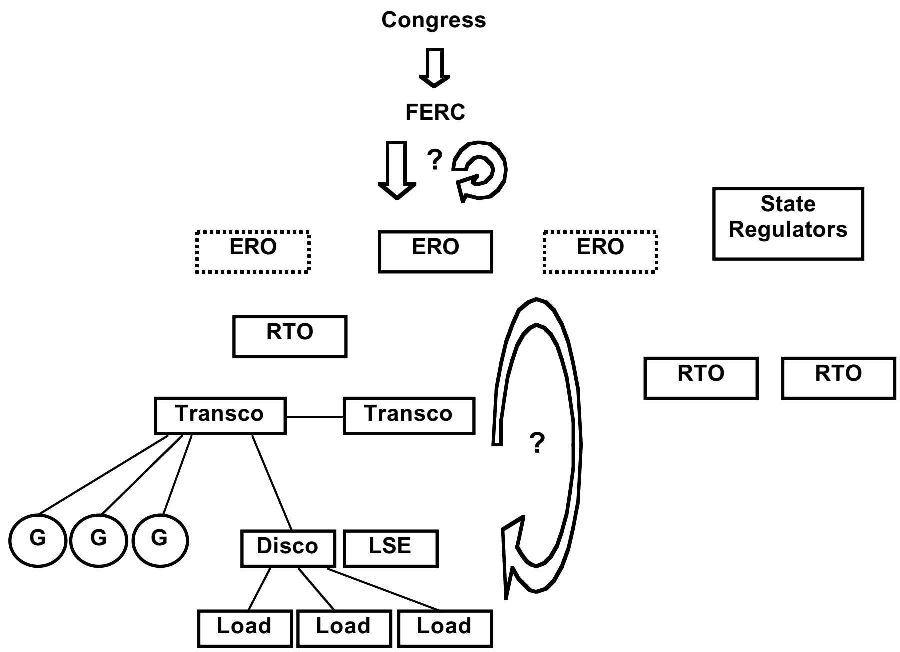
Scope and Authority

The questions of scope and authority for enforcing reliability rules are intertwined. There is general recognition that voluntary compliance with best-practice guidelines will not be sufficient in a competitive environment where individuals can profit by pushing risk onto others (Cook 2001). State regulatory authority is also not sufficient, especially because FERC has federal authority over interstate commerce. It appears that FERC does not now have sufficient authority to establish and enforce national reliability rules, and it certainly does not have authority to establish and enforce international rules that would cover entire interconnections.

Several bills have been introduced into the U.S. Congress to address reliability rules. The details of each proposal are in flux, so we do not debate them individually here. However, we discuss some of the basic concepts contained in the bills. As illustrated in Figure 5, all of the bills ask the U.S. Congress to give FERC authority to comprehensively address reliability issues for all electric utilities in the U.S. The bills differ in how they envision FERC exercising that authority, however, and to what extent reliability rules should allow regional diversity.

There are innumerable important details (and getting the details right is critical for any governance plan to

Figure 5: Who should participate in establishing reliability rules? Should FERC actively participate in the dialogue? What should the geographic scope be? Many questions remain concerning how reliability rules should be established and enforced.



succeed), but there seem to be four major questions associated with designing a reliability structure.

The first question concerns FERC's ongoing involvement in defining reliability rules. All of the proposals pass congressional authority through FERC. Some have FERC approve the initial formation of one or more Electric Reliability Organizations (EROs) and then allow FERC to delegate its authority to those organizations. Other proposals require the EROs to return to FERC for approval of each change in reliability rules. Some proposals allow FERC to take direct action to establish or modify reliability rules. Others require FERC to wait until a participant brings an appeal. The core issue is how involved FERC should be in ongoing details of reliability management. There is concern that FERC does not currently have sufficient staff with appropriate technical qualifications to take on the added function of participating actively in developing and enforcing reliability rules; it seems likely that FERC and/or EROs will require more technical staff in the future to deal with analyzing, establishing, defending, and enforcing reliability rules. Voluntary organizations may not be able to cope with the increased controversy that will likely surround reliability rules. Self-regulation works in other industries (the securities industry utilizes the National Association of Securities Dealers, for example) where federal agencies delegate power to nongovernmental entities (Michael 1993). Insuring that the EROs do not tailor rules and enforcement to serve the interests of favored parties rather than the interests of the public is critical for self-regulation to work.

The second question concerns national versus regional standards. All of the proposals before Congress recognize the physical differences among power systems in different regions of the country, and all allow differences in reliability rules when necessary. Striving for national (continental) rules and granting exceptions when necessary would reduce "seams" (differences among regions) issues and make it easier for market participants to operate in multiple regions. Allowing regions to develop reliability rules independently would mean that the rules could be tailored to the requirements and preferences of each region. The question may come down to who bears the burden of proof: Does a region have to prove that it needs a waiver from national rules? Or are all regional rules accepted as long as they are effective for insuring reliability? One possibility is to have national rules and definitions but allow region-specific determination of required reserve quantities and reliability goals/objectives.

A third question concerns how many EROs are established. If FERC establishes several EROs, then it is likely that there will be significant regional diversity. If FERC establishes a single strong ERO or if FERC itself becomes heavily involved in detailed rule development, then it is more likely that national or continental standards will emerge. Some have suggested that the regional transmission organizations (RTOs), strongly encouraged in FERC Order 2000, should also be the EROs. This is possible but raises concerns about a single organization establishing rules, performing some reliability functions, purchasing other reliability functions, judging performance, and imposing sanctions. It would be difficult for such an organization to appear to be impartial.

A fourth question concerns the involvement of the true "customers" of reliability decisions: loads (customers) and the public. These constituencies do not typically have strong technical backgrounds in transmission reliability and are also typically too small individually to participate in reliability decisions. In addition, electricity system reliability is not their primary focus. Yet they are the only reasons that the system exists, and they are the ones who pay the lion's share of the costs for both reliability and unreliability. Increasing the involvement of state regulators (as customer representatives) in developing reliability rules may be one way to address the issue.

Recommendations

DOE, FERC, and others can take a number of actions to improve the reliability of the bulk-power system:

- Promote passage of federal legislation that grants FERC authority over bulk-power reliability in the United States. FERC authority would cover all bulk-power participants, including all transmission owners (the municipal, rural cooperative, state, and federal utilities not now subject to FERC oversight as well as investor-owned utilities). In addition, FERC authority would cover all generators connected to the grid, power marketers and brokers, distribution utilities, and load-serving entities. Contracts between the system operators and each market participant should be considered substitutes for federal legislation only if federal legislation proves impossible to enact.

- Upon passage of the legislation suggested above, FERC would develop (or cause to be developed) and approve mandatory reliability standards and the associated compliance and penalty provisions required to implement such standards. That is, today's system of voluntary compliance with standards developed by a small group of industry insiders would be replaced by mandatory compliance with standards developed in an open and inclusive process.

- FERC should develop market-based penalties for failure to comply with reliability standards. That is, the penalties should be a function of the costs to the bulk-power system and to retail customers of the failure to comply. In addition, the penalties should recognize whether the failure to comply was intentional (e.g., the owner of the generator decided to sell capacity committed to contingency reserves as energy in another system) or was inadvertent (e.g., a generator suddenly tripped off line).

- To support compliance with mandatory reliability standards, FERC should develop metrics for reliability services. It is not possible to buy or sell what we cannot measure, nor is it possible to impose penalties on nonperformance with regard to something that we cannot measure. Metrics should be developed in an open, public forum and should be consistent throughout the country. There may be regional differences concerning how much of a particular reliability service is required, but the metric for assessing the quality of the service should be consistent. (The speed limit, for example, varies from road to road depending on local conditions, but the metric is consistently miles per hour.)

- FERC should conduct and publish an analysis of the benefits and costs of each reliability standard. This analysis, using historical data and simulation models, should show the pros and cons of different kinds of standards and of weaker and stricter levels for the particular standard chosen. For example, the current DCS requires that control areas recover from all disturbances within 15 minutes. Analysis could show the benefits and costs of changing the standard to 10 minutes (increased reliability, higher costs) or 20 minutes (decreased reliability, lower costs).

- FERC, DOE, and the National Association of Regulatory Utility Commissioners (NARUC) should develop and implement reporting requirements for reliability events. These requirements would provide for the collection of data that are now lacking on the number, extent, and effects of outages that interrupt service to retail customers. Separate requirements might be developed for distribution utilities and RTOs to reflect differences in distribution and bulk-power outages. These data should be made public to facilitate public choices about reliability needs and preferences.

- FERC should analyze differences among regions with respect to transmission topology, types and number of generating stations, types and magnitudes of retail load, and other factors to determine whether regional reliability standards are appropriate. This analysis should help FERC decide whether national (actually, North American) standards should be the default; if national standards prevailed, regional variances would be approved only with a clear demonstration of their value or of the need for them. If the study led FERC to decide that regional standards are preferable, national standards should be used only where regional differences are minor.

- FERC should establish compensation requirements for loads that are involuntarily curtailed. Required compensation would eliminate any incentive to use involuntary load curtailment as a resource simply because it would be cheaper than procuring adequate reserves.

- Reliability services established by FERC should be technology neutral. They should focus on the required function, not on the technology used to deliver the service. Demand-side solutions should be encouraged to complement historic generation-side solutions. Services like spinning reserve, for example, functionally involve real-power response to rebalance generation and load. The service should be defined based upon the function (real-power response within a defined time frame) not the technology (generation connected to the system).

- Control area size should be based on rational criteria. DOE should commission a study to determine why so many small control areas continue to exist and whether their numbers adversely impact system reliability by making coordination difficult or impeding commerce by increasing transaction costs. FERC should act to eliminate the incentives to operate small control areas if the study shows that they adversely affect the system.

Summary

Restructuring the electric power industry in the U.S. is dramatically affecting reliability management and oversight. The physics of the power system are not changing, but the commercial relationships and economic interests of various parties are. In a simplified power system, reliability requirements are straightforward, and reserve requirements are deterministic; however, reliability rules need to reflect the complexity of the real world, with which system operators have always had to grapple. In the face of strong, competing economic interests, reliability requirements must be defined clearly for each party. Metrics, pay for performance, and/or enforcement are required when competitive interests differ from communal ones. Metrics are developing slowly, and enforcement awaits resolution of governance issues and the establishment of a chain of authority for reliability rules. The historic voluntary structure that worked well for the vertically integrated utilities of the past is not adequate today.

Load has always been used as a reliability resource, at least in the last extreme and generally without consent. A market structure should be fostered in which loads (customers) could voluntarily respond to reliability needs and be compensated for their contributions. A competitive market could set the value of the contributions.

Managing reliability is managing risk. The unique features of AC electric power (the passive nature of the transmission system coupled with the need to continuously balance load with generation) result in a communal power system that exposes all users to the shared risk of system collapse. It is not practical to build a power system that is 100 percent reliable. Reliability rules establish how much risk the system will assume. Deciding how much risk to take and selecting reliability rules should be communal decisions.

Two major questions associated with reliability management are who decides on the acceptable level of risk (and the costs to maintain that level of reliability) and who takes the risk (and incurs the cost). Societal as well as individual interests must be considered.

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Alternative Business Models for Transmission Investment and Operation

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Introduction

A common theme in restructured electricity systems around the world is the unbundling of generation, transmission, and distribution and the creation of independent transmission entities that link competitive generation to regulated distribution. The transmission sector, which enables wholesale competition in the electricity industry, is viewed as the centerpiece of restructured systems. Consequently, the requirement that all market participants have nondiscriminatory access to the transmission system is the key requirement for facilitating competitive markets. The central question that this paper addresses is what transmission system governance structure and business model can most effectively support the objective of promoting competition through nondiscriminatory access to the grid. Transmission system business models define the relationship among the three basic business functions associated with the provision of transmission service: system operations, market operation, and grid ownership.

The complexity of system operations and the unique physical characteristics of electricity production and distribution necessitate considerable centralization of system operating functions to assure stable, reliable power supply. A debatable issue is the extent to which system operations should be combined with market operation, especially for day-ahead and forward trading; possibilities in this area are reflected in the diversity of market designs in the U.S. and abroad. The Pennsylvania-New Jersey-Maryland (PJM) Independent

System Operator (ISO), for instance, operates a day-ahead energy market and offers economic dispatch and unit commitment services. At the other extreme, the Texas system operator—the Electric Reliability Council of Texas or ERCOT—provides only real-time reliability-related services, including energy balancing, ancillary services procurement, and congestion management.

For the relationship between system operations and grid ownership, most current restructured systems have adopted business models based largely on the ownership of the grid. In the U.S., where a large portion of the grid is owned by investor-owned utilities, formation of nonprofit ISOs that *control* but do *not own* transmission assets has been an expedient approach. This strategy enabled restructuring to proceed without requiring that utilities divest their transmission assets. By contrast, in countries such as England and Wales, New Zealand, and Spain, where the grid was centrally owned by governments or private entities, for-profit Independent Transmission Companies (ITCs) were formed.

The main concern in this paper is the extent to which incentives for operational efficiency and reliability of the grid and for efficient investment in the transmission system are facilitated or hindered by business models that differ in their level of vertical integration of ownership and control, investment financing mechanisms, reward structure and regulation, nature of governance, and degree of financial control.

As we address these issues, some background about transmission needs to be kept in mind. First, transmission asset costs [including fixed and variable costs] constitute a small percentage of the total cost of electricity supply and generally run less than 10 percent of generation cost (Awerbuch, Hyman, and Vesey 1999). Furthermore, transmission costs consist mostly of investment costs.[1]

Another feature of transmission is that, although transmission and generation are complementary in the sense that transmission provides the means of transporting generated power to load, they are also substitutes because generation at a load center can reduce the need for transmission and vice versa. This substitutability was exploited by vertically integrated utilities through "integrated resource planning," whose objective was to optimize the allocation of investment between supply- and demand-side investments for the social good. The vertical separation of transmission and generation makes such coordination of investment much more difficult. In addition, the objective of transmission investment in a market with competitive generation extends beyond the maximization of social welfare.

Mitigation of market power and reduction of transfers between consumers and producers can sometimes be achieved by constructing transmission lines that do not represent socially optimal investments. Often a small investment in transmission may have large financial consequences for market participants. For example, a transmission line connecting two isolated, self-sufficient regions where local suppliers have market power will engender competition and reduce consumer prices although the line may hardly be utilized.

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[1]Leonard Hyman, in a private communication (October 2001) offered the following back-of-the-envelope calculation as an illustration of how insignificant the cost of transmission investment is relative to energy cost: We could add $5 billion/year to transmission capital expenditures (which now total $3 billion/year), depreciate the incremental assets over 10 years (vs. 40 years for existing assets), provide 20 percent pretax return on capital (vs. the current 12 percent) , and maintain the new assets in line with existing standards at a cost of about an extra 1 percent per year on the consumer's electricity bill. (Doing this for five years in a row would add approximately a total of five percent to the electricity bill). This calculation assumes no gains from efficiency improvements, trade or mitigation of market power. Any such gains would offset part of the added cost.

The Scope of a Transmission Enterprise

Federal Energy Regulatory Commission (FERC) Order No. 888 mandated open access to the transmission grid; FERC Order No. 2000 encourages and provides ground rules for the formation of Regional Transmission Organizations (RTOs) for providing nondiscriminatory access to transmission service for all market participants. These two orders define the roles and scopes of transmission enterprises. According to these orders, RTOs must, at a minimum, have the following characteristics:

- Be *independent* from market participants,
- Have appropriate scope and geographic configuration,
- Possess operational authority for all the transmission facilities under the RTO's control, and
- Have exclusive authority to maintain short-term reliability.

FERC identifies the seven functions that, at a minimum, an RTO must perform:

- Administer its own tariffs and employ a transmission pricing system aimed at promoting efficient use and expansion of transmission and generation facilities,
- Implement market mechanisms to manage transmission congestion,
- Develop and implement procedures to address parallel path flow issues,
- Serve as a supplier of last resort for all ancillary services required by Order No. 888 and subsequent decisions,
- Operate a single Open Access Same Time Information System (OASIS) site for all transmission facilities under its control with responsibility for independent calculation of Total Transmission Capability (TTC) and Available Transfer Capability (ATC),
- Monitor markets to identify design flaws and detect the exercise of market power, and
- Plan and coordinate necessary transmission additions and upgrades.

Order No. 2000 does not identify a preferred business model for transmission functions or a mechanism for financing transmission investment. It encourages innovative proposals that will meet the characteristics listed above. The remainder of this issue paper addresses candidate models, methods of evaluating them, and relevant international and domestic experience with these issues, as follows:

- The range of options for business models,
- Criteria for analyzing business models,
- International experiences with different transmission business models,
- Recent U.S. developments in for-profit transmission-only companies and the construction of direct current (DC) merchant transmission lines,

- The strengths and weaknesses of two "straw man" proposals that represent alternative business models: the nonprofit ISO and the for-profit ITC,

- Options for policy initiatives toward selecting business models for the U.S. transmission system, and

- Summary of the paper, conclusions, and recommendations.

The Range of Options for Business Models

From the perspective of customers (i.e., generators, loads, distributing entities, and other users of transmission services), transmission service providers (TSPs) in a restructured power industry should provide one-stop shopping for the transmission services needed to execute wholesale transactions. However, from a supply-side perspective, a TSP performs two generic functions: provision (ownership) and control (operation) of transmission assets. As part of its control function, a TSP must procure and deploy appropriate resources to relieve congestion and ensure system reliability. We subscribe to the premise that is widely accepted in the U.S. that, in order to avoid conflicts of interest, the TSP, regardless of its underlying business model, should not own generation assets or have a financial interest in any of its transmission service customers. In keeping with this premise, the TSP procures all the generation services it needs through short-term markets or long-term contracts. The principal criterion by which business models for TSPs are categorized is whether or not ownership and control of the transmission assets are vertically integrated. The two main categories of business models are:

- Separate ownership and control: control functions and interactions with transmission customers are handled by a system operator, and transmission assets are owned by separate entities;

- Joint ownership of transmission assets and control of the grid: both functions of the TSP are combined in a single entity.

Within each of these categories[2] are several options, described below, that are compatible with power industry realities. Some of these options capture the essence of existing U.S. and international structures, but not all are compatible with the FERC RTO guidelines listed above.

Separate Ownership and Control of Transmission Assets

System operator publicly owned; assets owned by utilities, generators, municipalities, and private investors

Under a separate ownership and control situation, the system operator is a public enterprise or government agency issuing instructions to owners of transmission assets regarding asset maintenance, operation and investment. The system operator faces soft incentives (because there are no residual claimants, i.e., no share-

[2]This classification is based on Awerbuch, Crew, and Kleindorfer (2000), pp. 23–40.

holders that would gain from financial incentives or bear the consequences of financial penalties) and is charged to behave fairly and efficiently and to maintain adequate system reliability.

System operator jointly owned by the owners of the transmission assets and operated as a nonprofit organization; assets owned by utilities, generators, municipalities, and private investors

As in the previous situation, the system operator in this case issues instructions to transmission asset owners. However, the owners of the transmission assets might be able to form coalitions and use their voting power to favor their own facilities. A nonprofit orientation amplifies this effect by eliminating potential tradeoffs between profit from efficient utilization of facilities and the motives of system operator owners wishing to favor their own facilities. On the other hand, sharing the profits of a for-profit system operator is more likely to induce owners to opt for efficiency (and higher profits from system operations) rather than pursuing the selfish motives of the party they represent.

System operator jointly owned by the owners of transmission assets and operated for profit; assets owned by utilities, generators, municipalities, and private investors

This case is similar to the previous one, but the potential for profit may moderate the tendency to form coalitions.

System operator established as an independent nonprofit company (ISO); assets owned by utilities, generators, municipalities, and private investors

This structure exists in California, Texas, and PJM. The ISO's independence in this model can make the formation of coalitions difficult, depending on the composition of the governing board. When the governing board is composed of stakeholders, as was the case in California prior to January 2001 and is the case in Texas, coalitions may still be formed.[3]

Joint Ownership and Control of Transmission Assets

Transmission Service Provider owned by a public enterprise

In this configuration, transmission assets are owned by a public entity, so all externalities within the region are internalized. In other words, because a public entity owns all the assets, there is no possibility that the action of one transmission owner may adversely affect another transmission owner. The structure of Western Area Power Administration (WAPA) is similar to this model.

[3]The fundamental shortcoming of this structure was articulated by the CAISO Market Surveillance Committee in the following observation with respect to reserves: "We note that the ISO does not bear the final cost of the reserves that it acquires. These are passed on to the users of the system. However, as a fledgling institution, the ISO has a very strong incentive to avoid serious reliability problems. The thorny problem of providing operators the incentive to both minimize costs and ensure reliability is a long-standing one in the electricity industry." Similar incentive problems exist for transmission system operation (CAISO, "Annual Report on Market Issues and Performance", June 1999).

Transmission Service Provider owned by utilities, generators, and municipalities and operated not for profit

When the TSP is operated not for profit, owners who are also market participants may favor investments in generation assets, which would produce profits, over investments in transmission, which would not when these investments are substitutable.

Transmission Service Provider owned by utilities, generators, and municipalities and operated for profit

This case is similar to the previous one, but the potential for profit from transmission investments weakens the motive of transmission company owners to favor generation investments that would benefit the parent companies over transmission investments that would improve the service provided by the TSP.

Transmission Service Provider owned by a single regulated utility and operated for profit

This case is similar to the previous one except that the ownership is in the hands of a single utility. Competitors and customers served by the transmission company may fear discrimination against them in favor of the utility owner. In other words, the regulated utility operating the transmission grid may favor its own affiliated resources and customers at the expense of other customers and competitors that wish to use the transmission system. The RTO plan proposed by Entergy fits into this category.

Transmission Service Provider organized as for-profit, independent transmission company (ITC)

In this configuration, the ITC has no other facilities of its own that it might differentially favor, and its profit incentive will drive its pricing and investment decisions. Its monopoly status requires regulation to ensure just and reasonable prices.

Criteria for Analysis of Alternative Business Models

Alternative business model for transmission enterprises may be evaluated using several criteria:

- Market efficiency,
- Operational efficiency and system reliability,
- Transmission access and interconnection policy,
- Investment and innovation in the transmission grid,
- Governance and regulatory oversight, and
- Political feasibility.

As noted above, system operators under the separate ownership and control paradigm and TSPs under the joint ownership and control paradigm can come in many forms; a critically important consideration is their roles in market operation and the extent to which they are affiliated with entities that use the transmission system. In any case, the central role that such entities play in the market and their monopoly status will necessitate some form of regulation. We assume that FERC's RTO initiative will move ahead so that any business model for transmission entities will function within the RTO framework. The subsections below discuss the separate ownership and control and joint ownership and control paradigms using the above criteria.

Market Efficiency

Economic efficiency is achieved when the price of goods and services is close to their marginal costs and when the price of scarce resources results in efficient rationing. Because we assume that the TSP would not be affiliated with wholesale or retail market participants, bias or deliberate discriminatory treatment should not be a concern. Nonetheless, it is not clear which of the TSP structures discussed above would be more likely to result in efficient price signals that would facilitate competition, reduce exercise of market power, and encourage efficient investment in generation (in terms of quantity and location). The key questions are whether a system operator under separate ownership and control or a TSP under joint ownership and control would have inherent advantages or disadvantages in managing scarce transmission resources, operating a balancing market, and procuring ancillary services that are essential for system operations. To promote market efficiency, a TSP must manage congestion efficiently and provide appropriate price signals to guide decisions about production, consumption, and location of load and generation and to reduce abuse of market power. It is not clear whether either the separate ownership and control or joint ownership and control approach has inherent advantages or built-in incentives that would help achieve these objectives or whether an incentive system exists under either approach that would induce the TSP to come up with rules and protocols that will achieve the goal of economic efficiency. Most likely, any business model would have to include a specified set of rules and protocols that are consistent with FERC RTO principles and that will foster the desired behavior by the TSP whether operation and ownership of the transmission assets are joint or separate.

Another concern is the extent of transaction costs for rebundling required transmission assets. A system operator must deal with the added complication of negotiating with independent transmission owners (TOs) for increased use, enhancement, and maintenance of their assets. When the TOs are involved in the governance of the system operator, committee decision-making processes involving TOs create an opportunity for transaction costs and organizational inertia.

On the positive side, a separate ownership and control structure, particularly one in which the system operator is nonprofit, would be more amenable to enforcing a set of market protocols that are designed to pursue market efficiency. Adoption of such "socially efficient" protocols is more likely when the system operator operates as an ISO that is not governed by stakeholders. One question is whether the added efficiency achieved by a separate ownership and control structure would cover the added transaction costs and inefficiencies resulting from the separation between ownership and control of assets.

The joint ownership and control models that involve public ownership under nonprofit operation raise concerns about the transparency of motivation for efficient operation and decision-making. In a sector such as electric power where economic drivers are primary, a structure that puts technical groups or committees in charge of key components is highly problematic. Technical committees tend to emphasize technical integrity and often compromise economic principles for political expediency. Such compromises have manifested, for instance, in congestion management protocols that opt for spreading the costs of congestion relief to all users rather than assigning them to those who cause the congestion. Adoption of such rules has, in some systems, resulted in gaming and market disruptions. A related problem is absence of residual claimants (e.g., shareholders who have a claim to gains from efficient operation) in the first two options under the joint ownership and control structure. This absence may create a conservative bias in operating decisions (e.g., derating transmission lines or overprocurement of reserves in order to avoid economically justifiable risk), which may limit trade and foster the exercise of local market power.

In many respects, the ITC option may be viewed as the *gold* standard of the joint ownership and control structure. The only business of the ITC is transmission, so it has no incentive to discriminate against any particular customer.[4] This contrasts with the option of a TSP owned by a single utility, which would have a strong incentive to favor its own customers, generators, and loads. Mitigating these tendencies would require considerable regulatory intervention. The potential to discriminate is attenuated when transmission customers or several companies jointly own the for-profit TSP. Unfortunately, profit incentives are also attenuated under such joint ownership, and the potential for formation of coalitions may present additional problems. Specifically, groups of owners representing diverse interests of transmission users may form voting blocks and trade (among themselves) support of inefficient policies that favor the interests of the various coalition members (e.g., voting against a market-power-mitigation measure in exchange for a vote supporting the spreading of intra zonal congestion costs among all users).

Questions about how horizontal integration of transmission ownership and control affect market efficiency must be framed in the context of the geographical scope and market-making authority of TSPs. The answers depend on whether we assume a highly centralized transmission organization such as PJM, which operates a day-ahead energy market and provides unit commitment services, versus a decentralized organization such as ERCOT. Similarly, when ownership and control of transmission assets are not joined in a single entity, horizontal integration of ownership and control may have advantages or disadvantages for efficient coordination of adjacent markets.

A TSP's objectivity towards the users of transmission services may not completely eliminate the potential for price distortions and economic inefficiency. The substitutability between transmission and generation investment puts a for-profit TSP operating under the joint ownership and control structure in competition with the generators it serves. This TSP may have perverse incentives that may bias its congestion management practices to favor "wire solutions" over "generation solutions" in its investment policy. These concerns must be addressed through incentive regulation that rewards market efficiency and also punishes inefficiency. For instance, the Transmission Services Scheme in England and Wales provides the National Grid Company (NGC) with financial incentives to reduce transmission "uplift" costs, which may be viewed, in part, as a crude proxy for market inefficiency. In that regard, system operators under a separate ownership and control paradigm may be more objective in choosing between wire solutions and generation solutions, which will result in price signals and investment plans that promote economic efficiency.

[4]Of course, the ITC may engage in monopoly pricing and must therefore be regulated.

Operational Efficiency and Reliability

The business structure of a TSP affects its incentives to operate the transmission system efficiently (i.e., at least social cost) and reliably. One of the main concerns about nonprofit TSPs is that they have little to gain from reducing costs of operation through, for example, the judicious procurement of ancillary services. In the absence of a profit motive, TSPs are judged primarily on system reliability performance without any consideration of the economies (efficiency), so they have an incentive to operate conservatively (at increased cost). By the same token, there is a legitimate concern that a for-profit TSP will have the opposite incentive—to sacrifice system reliability in favor of profit. Restraining the natural tendencies of either structure requires the specification of appropriate rules of the road and a well-crafted system of governance and regulation. This requirement shifts the emphasis to determining what form of organization is easier to regulate and how to do so effectively.

Operational efficiency and system reliability can be achieved by alternative means, including short-term operational procedures, which include dispatch of generation resources, maintenance of transmission assets, and investment in innovation. Separation of these functions as under the separate ownership and control approach creates risks that need to be mitigated by means of contracts and risk management, which result in increased costs. An advantage of the separate ownership and control approach, however, is that the system operator is indifferent to the utilization of transmission or generation resources to perform its duties and should thus opt for the most efficient solution to a reliability problem when there is a choice between investment in generation resources (e.g., Reliability Must Run (RMR) contracts) or transmission assets. The analysis of the separated functions option must compare the benefits of separating transmission ownership from operation to the costs involved.

Transmission Access and Interconnection Policy

The premises of FERC Orders Nos. 888 and 2000 and the subsequent decisions concerning the formation of RTOs are that widespread interconnection and direct access to the transmission network will expand the scope of the market and foster market efficiency. Determining which transmission organization business model will best facilitate that vision is difficult because of many political and regional considerations, including the tension between state and federal jurisdictions. More pragmatic questions focus on whether certain organizational structures would expedite implementation of the RTO vision in different parts of the country and whether and how separate ownership and control and joint ownership and control structures can coexist. Considering the option of accommodating diverse organizational structures raises questions about coordination of operations and investment across seams between control areas or more generally RTOs. The principal concern is that decentralized investment and control of transmission facilities can result in loop flows and other network effects; in other words, individual transmission operators and investors may behave in ways that affect interconnected transmission grids. Such externalities may be inconsistent with the overall efficiency of operations and investment. The main advantage of the separate ownership and control paradigm is that separation facilitates the system operations of the grid combining the transmission assets owned by diverse organizations—e.g., utilities, private owners, municipalities—over a large geographic area. To the extent that an organization based on separate ownership and control can enforce its decisions, this integration, which enables one-stop shopping for transmission services over large regions, internalizes many of the externalities inherent in the *transportation* of electricity over meshed transmission networks. However, as the degree of horizontal integration of transmission assets serving adjacent geographic areas increases, the above rationale for vertical separation (i.e., that it is an effective way to consolidate operation of diversely owned resources) becomes less compelling, and the arguments in favor of joint ownership and control become stronger.[5]

If control areas are not horizontally integrated, the issue of seams must be explicitly considered. Efficient coordination among adjacent control areas or, more generally, RTOs depends more on the consistency of the congestion management protocols than on business models. It is difficult to assess the impact of alternative business models on efficient coordination at the seams. Mergers and standardization of protocols among control areas are the ultimate solutions to seams problems; the limited experience with restructuring to date appears to suggest that merging control functions is easier without merging asset ownership.

Investment and Innovation

Creating incentives for transmission system investment and innovation to congestion and expand the scope of the competitive market is a central issue in electricity industry restructuring. According to Paul Joskow[6] (1999), "Transmission investment decisions cannot rely exclusively on market mechanisms. They are lumpy, involve externalities, and are characterized by economies of scale. Restructuring experience to date shows no evidence that market forces will draw significant entrepreneurial investment into transmission capacity." Consequently, transmission expansion requires centralized planning and investment. How are activities hindered or facilitated by separation of control and ownership? To address this question, we have to consider what mechanisms the alternative business models offer for creating appropriate economic signals that provide incentives for efficient investment and innovation with adequate capability to finance these investments and reward ownership of assets.

Under the separate ownership and control paradigm, the system operator plans and evaluates transmission expansion. The market signals for such investments result from: congestion management protocols; locational energy prices; the definition, allocation, and settlement of transmission rights; and the regulation of return on transmission assets. Investments in transmission are made by the owners, who are responsible for the financing and are rewarded with: regulated returns on their investments, transmission rights, and/or direct benefits from the transmission assets, which may complement and enhance the owners' ability to buy or sell energy. Merchant transmission investment is also possible, but, because of externalities (except in the case of DC lines), such investments would need to be approved by the system operator as well as the regulatory authority. The separation of functions under the separate ownership and control structure can, however, lead to different objectives for the system operator and the TOs, as has been seen in California with regard to the California Independent System Operator (CAISO)-proposed expansion of Path 15.[7]

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[5]This argument is based on the well articulated discussion in Joskow 1999.

[6]Merchant DC line proposals such as those proposed under the Neptune Project and by TransEnergie are notable exceptions that will be discussed below.

[7]Although the cost of this transmission expansion is only about $300 million, which is relatively small in comparison to the estimated $70 million in annual congestion cost, Pacific Gas and Electric (PG&E) argued against expanding Path 15 on the grounds that generation expansion plans would make this transmission investment unnecessary. The ISO argued that savings to northern California consumers alone justified the transmission expansion, which was eventually approved.

One advantage of the separate ownership and control structure is that the system operator is indifferent to solving congestion problems by means of either energy generation displacement or through transmission investment. Such indifference may lead to a relatively balanced and socially efficient investment pattern and may also enhance the credibility of the system operator's recommendation for transmission expansion, which would facilitate approval by state commissions of rate increases required to finance such expansion. It is worth noting that the current prevailing separate ownership and control structures in the U.S. have fallen short in producing transmission investment, which suggests that separate ownership and control bias toward "wire solutions" is essentially nonexistent.

Reliance on market-based signals for investment in systems using transmission rights settlements and dispatches of RMR resources to relieve congestion raises concern because the patterns of nodal and zonal prices upon which market-based expansion initiatives must rely are very sensitive to reliability (i.e., security) criteria and are highly volatile. Such uncertainty is likely to discourage market-based transmission investment.

Settlements of transmission rights awarded to investors can, in principle, produce a market-based income stream, but the lumpiness of transmission investments as well as the issues of externalities and economies of scale make it difficult for investors to gauge the precise amount of transmission capacity at which transmission rights income offsets the costs of the investments. Consequently, compensation to TOs cannot be guaranteed from solely transmission rights revenues, which, in most cases, cannot be relied on to provide adequate cost recovery. These revenues would need to be supplemented or replaced by an uplift charge that relies on a regulated-return-on-investment approach. A major weakness of the separate ownership and control structure in this regard is that setting the regulated return on investment in transmission on the basic cost (book value) of transmission assets rather than on the contribution of such assets to the market and to system efficiency (market value).

As noted earlier, transmission costs represent a small fraction of the overall costs of electricity, yet relatively small investments in transmission may have a major impact on economic efficiency and system reliability. Furthermore, in the context of deregulated markets, it is possible that a transmission investment that contributes little to the reduction of social costs may have a significant impact on transfers between consumers and producers due to mitigating market power. For example, a line between two self-sufficient areas may not carry much flow, but its presence creates competition in each of the local markets, thereby mitigating market power exercise and reducing prices to consumers in both markets. In this situation, consumers clearly benefit from the investment, but financing may be difficult. When control and ownership of transmission are separated, a major challenge to investment and innovation is the creation of a financing linkage between those who benefit from the investment and those who make the investment.

Traditional regulated-rate-of-return approaches that compensate investments based on cost and allocate the compensation to users on some pro rata basis are ineffective in this regard. One explanation offered by some speakers at U.S. Department of Energy (DOE) public workshops is that the traditional rates of return approved by public utility commissions for transmission investments are inadequate considering the risks associated with such investments in restructured markets.[8] The proposed solution is to raise that rate of return substantially. Although this approach may work in the short run, "throwing money at the problem" is an overly simplistic and naive solution that may ultimately result in inefficient investment.

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[8]This point was raised by two speakers at the public workshop in Phoenix, Arizona.(September 28, 2001).

Under the joint ownership and control approach, it may become possible to separately track the costs associated with operations, assets, maintenance, and investment. However, the key advantage of the joint ownership and control approach is that the impact of investment on operations may be internalized by the TSP and the compensation for asset ownership may be based on value added by the assets rather than their costs. As noted above, it is doubtful that incentives alone can induce a TSP to develop a transmission pricing scheme and congestion management protocol that would result in efficient price signals. The pricing scheme requires regulatory oversight and approval. However, it might be possible to develop a performance-based compensation scheme that would internalize the complementarity between operations and investment in achieving the desired "end product" transmission system.

The main problem lies in defining and measuring that end product. Is it defined by interconnection, transaction volume, absence of congestion, or some degree of economic efficiency and effective competition? Evaluation of the performance of the TSP in the combined ownership and control approach hinges on whether it is nonprofit or for-profit. For a nonprofit TSP, there may be a tendency to use reliability as the primary measure of performance, which would lead to overly conservative operation and therefore overinvestment, the costs of which would be borne by consumers. With a for-profit TSP under combined ownership and control, the challenge is to develop performance-based regulation (PBR) that rewards efficiency and penalizes inefficiency. Such a regulatory scheme would balance incentives for efficient and reliable operation with those for investment and innovation so as to result in a stream of revenues capable of financing requirements for such investments.

Governance and Regulatory Oversight

The key regulatory questions are:

- What is the effect of vertical integration of operation and ownership on the efficacy of regulation?
- Which organizational structure is easier to regulate: a nonprofit TSP, which is typically governed by a board of stakeholders or an independent board, or a corporate, for-profit TSP?

Regulation encompasses issues of governance of the system operator and the determination of appropriate compensation for the TOs. If the system operations are provided for by a for-profit organization, then the regulator would also have to regulate the system operator's profit. In principle, under the separate ownership and control paradigm, the regulator has direct control of the compensation of TOs and consequently can protect consumers while directly influencing investment decisions by authorizing appropriate levels of return on investment incorporating the consideration of attendant risks. This is the prevailing model in the U.S. where all restructured systems to date fall into the ISO category with TOs being compensated under a cost-of-service or rate-of-return (ROR) scheme. ROR regulation provides a prima-facie basis for achieving fairness between shareholders and rate payers by setting the allowed rate of return at a level that justly compensates the owner for investment and risk taking so as to be able to attract capital.

At least in theory, ROR is fully cost based, allowing cost increases or reductions to flow directly to the customers of the regulated firm. The emphasis here is on fairness at the expense of efficiency. ROR has been popular with regulators and utilities because it is well understood and its cash flows and risks are relatively transparent. For transmission, however, ROR may not be the appropriate approach to provide incentives for investment and attract capital. Clear evidence that this approach is inefficient is the lack of investment in transmission since the onset of electricity industry restructuring in the U.S., especially in contrast to the extensive investments in generation during the same period. At the DOE public workshop in Phoenix, Arizona (September 28, 2001) at least one presenter argued that the allowed rate of returns for transmission investments does not properly reflect the risks associated with such investments under deregulation and that higher rates are needed. In any case, the ROR approach puts the regulators in the position of being "penny wise and pound foolish" with regard to transmission investment. By shaving a few points of the cost of transmission, which constitutes a small percentage of the total cost of electricity, the regulator may deter transmission investments that may bring impacts that greatly exceed their costs through efficiency improvements and market power mitigation, which will affect transfers from consumers to producers.

With regard to the system operator function, we focus on the nonprofit ISO model, which is the prevalent structure in the restructured electricity systems in the U.S. The major advantage of this model is that it requires only light-handed regulation. The absence of the profit motive leaves no role for the regulator in setting prices other than trying to influence the allocation of charges among customer groups. The California Public Utility Commission, for instance, takes an active role in protecting residential customers and intervening in CAISO tariff cases before FERC. When the ISO is independent of transmission users and owners, it has no motive to be unfair. The fact that an organization is nonprofit does not mean that it has no incentives to control cost, but the objectives of a nonprofit firm may be different and more complex than those of a for-profit firm in the same business, making it more difficult to monitor the nonprofit's performance. Decisions in a nonprofit organization are driven by personal managerial objectives and compromises with the stakeholders, some of who are profit driven.

No one argues that it is possible to devise a regulation scheme that creates incentives for a transmission organization to develop an operation and settlement protocol that will result in efficient markets. Hence, realistically, whichever organizational form is chosen, the market design will be determined through a regulatory review process, which will include protocols for managing congestion, scheduling and dispatching power, balancing market operation, and procuring ancillary services.

The ISOs in the U.S. are governed by boards of directors that are composed of either stakeholders, as in the case in ERCOT and in California (before January 2001), or independent members, as is the case in the PJM New York and New England ISOs. Governance by a stakeholder board circumvents the nonprofit aspects of the ISO because the stakeholders, some of who represent for-profit companies, will try to influence the ISO rules and procedures to maximize their own profits. The result is an "Ouija board" decision-making process whose outcomes are unpredictable and unlikely to consistently promote efficiency.

In the case of joint ownership and control, there is legitimate concern that the TSP will exercise its monopoly power to the detriment of transmission service customers. To prevent such abuse, a more heavy-handed regulatory scheme may become necessary. The objective of such a scheme should be to reward efficiency and penalize inefficiency. This is easier to do when the TSP operates for profit, such as an ITC, because then a PBR scheme can be designed to induce appropriate risk taking on the part of the TSP and proper balancing among efficient operations, investment in new facilities, and innovation. Such a PBR system has not yet been designed or implemented, however, and none of the proposed approaches has been proven to produce the ideal desired outcome. The U.K. Transmission Services Scheme, which provides the grid operator with financial incentives to reduce transmission "uplift" costs, is a good example of a practical PBR approach and a step in the right direction. The underlying assumption of that scheme is that the TSP's performance can be measured in terms of the uplift charge that the TSP must recover from its customers To some extent, high uplift charges indicate inefficient operations and/or a high level of congestion costs. The uplift charges can be reduced by improving operational efficiency or expanding the transmission system. The main challenge in such a scheme is to determine the proper yardstick for uplift charges.

Price-cap regulation (PCR), which is common in the telecommunications industry and is widely used throughout the world for utility services, may also be appropriate, at least as an initial mechanism for an ITC. This scheme provides incentives for cost minimization by decoupling regulated price levels from the firm's costs. The price levels are generally defined by a price-cap index, but firms are often given flexibility, which, in the case of transmission pricing, would enable the TSP to respond to short-term demand fluctuations. Pure PCR allows the regulated firm to retain the fruits of its successes within the constraints of the price level and the period of the price cap. Other variants would involve some sort of risk sharing that would protect the firm against catastrophic failure but would also limit its potential windfall profits.[9]

Political Feasibility

The attractiveness of the separate ownership and control paradigm and particularly the nonprofit ISO model is that it overcomes ownership barriers in the transmission system and facilitates competitive markets by internalizing externalities and creating "one-stop shopping" for transmission. This relative advantage decreases with the degree of horizontal integration of transmission assets. The combined ownership and control structure can also offer similar services. However, the extent to which such horizontal integration can be achieved is largely a political question. In California, the ISO structure was chosen largely because it was politically infeasible to require the three major investor-owned utilities to divest their transmission assets. Even when the state considered purchasing the transmission assets from the utilities as a way to keep them solvent, the idea of consolidating ownership of these assets in the hands of the ISO was not considered. The divestiture and horizontal integration of transmission assets is a necessary condition for vertical integration of ownership and control with significant geographical scope so that most of the externalities associated with operation and investment can be internalized. However, the authority to force divestiture may involve state and federal jurisdictional disputes as well as other political considerations. For example, a considerable fraction of the transmission assets in the northwest and the southeast are owned and controlled by the Bonneville Power Administration (BPA), Western Area Power Administration (WAPA), and the Tennessee Valley Authority (TVA), so the creation of any new transmission organization requiring the transfer of ownership of these assets would entail new congressional legislation. Similarly, transmission assets owned by public power and municipal entities such as the Transmission Agency of Northern California (TANC), New York Power Authority (NYPA), and Los Angeles Department of Water and Power (LADWP) are difficult to transfer to for-profit enterprises due to "private-use" tax rules, which apply to assets funded through

[9]For a more detailed description of PCR, see Awerbuch, Crew, and Kleindorfer (2000).

tax-exempt bonds. Violation of private-use rules can make tax-exempt bonds retroactively taxable.[10] Such tax restrictions might also prevent public power resources from participating in RTOs without requiring the transfer of ownership. Joining an RTO, even on short-term basis, may prevent a public power entity from issuing tax-exempt bonds to finance new transmission facilities. Thus, seeking a new ruling from the Internal Revenue Service on such issue, might be necessary regardless of the business model selected.

Table 1 summarizes the considerations discussed in this section as they apply to the alternative business model options.

International Experiences

Transmission organizations have taken different forms in various countries. A study of the experience of transmission organizations in Australia, Argentina, Chile, England/ Wales, and Norway indicates that each country is seeking to improve its existing organizations. The experiences with transmission in these countries have varied widely. A key objective of our study was to investigate the nature and ability of incentives to motivate investment in improving/expanding the transmission system. Each system we studied has its own specific incentives whose direct applicability to other jurisdictions' or systems may be limited. Nevertheless, the lessons learned from the various systems may be valuable in designing incentives for transmission organizations in the US. This subsection reviews the key characteristics of the transmission organizations of the five countries mentioned above. For each system, the salient characteristics are analyzed, and the overall experiences are summarized noting features that may be useful in other jurisdictions. Specifically we examine the following aspects of each system:

- Ownership,
- Transmission tariffs,
- Ownership obligations,
- Transmission planning requirements,
- Investment incentives,
- Means of recovery of new investment,
- Role of customers in transmission system expansion, and
- Regulatory body.

Argentina

Argentina was among the first countries to restructure its electricity system. Starting in the early 1990s, Argentina's system restructuring was accompanied by the broad selling off of generation and transmission assets, mostly to foreign entities. The key characteristics of the Argentine transmission system are summarized in Table 2.

[10]This issue was raised by Mr. Gary Schaeff of Large Public Power Council (LPPC) at the DOE Atlanta Workshop (September 26, 2001)

Table 1: Classification of alternative business models

		Market efficiency	Operational efficiency and system reliability	Transmission access and inter-connection policy	Investment and innovation in transmission grid	Governance and regulatory oversight	Political feasibility
Separate ownership and control	**System operator publicly owned; assets owned by market entities**	No motive for inefficiency but weak incentives to facilitate trade	Likely to favor reliability over efficiency (least cost)	Will provide fair and equitable access	Credible with PUCs but may be difficult to attract investment	Light-handed regulation of system operator and ROR for assets	Easy to implement; requires no transfer of assets
	Nonprofit system operator jointly owned by transmission owners; assets owned by market entities	Owners can form coalitions to favor their facilities	Likely to favor reliability over efficiency (least cost)	Owners can form coalitions to favor their facilities	Likely to favor generation solutions	Lack of residual claimants complicates governance of system operator	Requires no transfer of assets but may face objection due to fear of bias
	For-profit system operator jointly owned by TOs; assets owned by market entities	Profit from increased trade moderates selfish interests of TOs	Incentive regulation can improve balance between efficiency and reliability	Profit from increased trade will moderate selfish interests of TOs	Profits from transmission business may offset bias toward generation solutions	PBR of system operator can incentivize efficient operation. ROR for investment	May face objections resulting from fear of bias and fear of monopoly power abuse
	Nonprofit independent system operator (ISO); assets owned by market entities	Neutral toward market participants; Likely to police market power	Likely to favor reliability over efficiency	Neutral toward market participants; Likely to police market power	Credible planning but may be difficult to induce TOs to invest and innovate	Light-handed regulation of system operator but difficult to monitor efficiency	Politically expedient. The currently prevailing solution in U.S.
Joint ownership and control	**Publicly owned TSP**	Externalities internalized but weak incentives to facilitate trade	Likely to favor reliability over efficiency (least cost)	Will favor native constituency over merchant transactions	Acts in the public interest to plan and expand transmission	Light-handed regulation of operation and investment	May require IRS ruling to operate under RTO
	Nonprofit TSP owned by market entities	Owners have incentive to favor their own affiliates	Likely to favor reliability over efficiency	Owners have incentive to favor their own affiliates	Favors generation over transmission investment (no profit from transmission)	Light-handed regulation but market oversight needed	Requires consolidation of assets or coalition of asset owners; Problems with public entities
	For-profit TSP jointly owned by market entities	Owners have incentive to favor their own affiliates	Profit motive shifts scale toward efficiency	Profit motive reduces tendency to favor owners assets	Profit from transmission reduces bias toward generation investment	PBR can incentivize efficient operation and investment	Requires consolidation of assets or coalition of asset owners. (e.g. Desert Star). May face objections
	For-profit TSP owned by a single regulated utility	Controlling tendency to favor owners assets may lead to a constrained market	Traditional operating mode likely to be efficient and reliable	Tendency to favor affiliates	Follows traditional planning and investment paradigm	PBR can incentivize efficient operation and investment. Oversight needed to prevent bias	Relatively easy to implement but may face opposition from other market entities
	For-profit independent TSP (ITC)	Incentives to mitigate market power of generators providing ancillary services and offers for congestion relief	PBR provides incentives for efficiency and reliability balance	PBR provides incentive for increasing access	Interaction between operational efficiency and investment is internalized, but ITC may favor wire solutions	PBR based on performance simplifies regulation. Independence eliminates need to monitor bias	Frequires consolidation of assets. Publicly owned assets may present legislative challenges

Table 2: Summary of the Salient Characteristics of the Transmission System in Argentina

Ownership	There are seven private transmission grid companies. TRANSENER owns transmission networks across the entire country, and six companies own regional transmission systems. Each company has to obtain the required license from the Argentinean regulator.
Transmission tariff	Charges consist of a fixed component for the recovery of investment costs and a variable component for recovery of operating and maintenance expenses.
Ownership obligations	To provide nondiscriminatory access and service to all customers (independent of their size)
Transmission planning requirements	No systematic planning; expansion plans require regulatory approval. No entity in the country has responsibility for planning transmission.
Investment incentives	There are no incentives to expand the grid by TRANSENER or any of the regional companies. Any expansion has to be entirely paid for by customers.
Means of recovery of new investment	Not applicable
Role of customers in transmission system expansion	Critically important because any expansion of the transmission system has to be requested and financed by the customer
Regulatory body	Ente Nacional Regulador de la Electricidad (ENRE)

Six companies own Argentina's regional grids, and one owns the transmission networks that span the country. Operation/control of the transmission system is separated from ownership. An ISO is in charge of transmission operation/control as well as operation of the electricity markets.

The responsibilities of the Argentine ISO do not include planning. In effect, there is no single entity in Argentina whose charter includes transmission planning. An undesirable aspect of transmission system expansion/improvement in Argentina is its dependence on the willingness of transmission customers to directly bear the burden of any new investment. There are no incentives for the transmission owners to expand/improve the transmission system, and virtually no new major transmission projects have been undertaken since the onset of the restructuring process in Argentina.

Australia

The restructuring of the electricity system has proceeded at different rates in different regions of Australia. Although a single electricity market has been established for the entire country, transmission organizations vary from region to region. Table 3 summarizes the characteristics of Australia's transmission system.

Table 3: Summary of the Salient Characteristics of the Transmission System in Australia

Ownership	Each Australian region has one or more state-owned regional transmission companies that own a transmission grid. In addition, there are non-state-owned companies that own transmission assets across the regions. Transmission-owning companies may be either regulated or nonregulated.
Transmission tariff	For regulated transmission-owning entities, there are regional pricing structures that are determined with regulatory approval by each region. The transmission prices consist of connection fees—so called shallow connection costs, demand charges based on peak and shoulder loading, and energy charges based on usage. Typically, the transmission tariffs are based on (CPI-x) regulation. For unregulated transmission-owning entities, transmission prices are market based and determined from the offers and bids for transmission capacity. In this way, capacity is treated, in effect, as a commodity.
Ownership obligations	All transmission-owning entities must provide nondiscriminatory service to all customers. Most of the state-owned companies have obligations with respect to transmission planning. The nature of additional obligations may vary regionally and depends whether or not the transmission-owning company is regulated.
Transmission plan ning requirements	Each stated-owned transmission company has to prepare an annual statement discussing planning activities. Each region has its own requirements regarding the nature of this statement. Each state-owned transmission company has responsibility for transmission planning. Any entity, including a non-transmission-owning company, is permitted to make investment in transmission assets.
Investment incentives	In the case of regulated assets, there are no clear incentives for expansion of the transmission system. For unregulated assets, the incentives are the future revenue streams for transmission services.
Means of recovery of new investment	The regulated transmission-owning companies may not necessarily be able to recover their investments in additional transmission facilities. The unregulated entities face the usual risks associated with markets and consequently may be able to receive compensation that exceeds their investment.
Role of customers in transmission system expansion	The generators work with the transmission-owning companies to improve the transmission system to avoid or eliminate congestion amd to plan new investments that may be required.
Regulatory body	There are two national regulators: • The National Electricity Code Administrator (NECA), which is in charge of administering and enforcing the Electricity Code, and in that capacity regulates all transmission-owning companies • The Australian Competition and Consumer Commission (ACCC), which handles all aspects related to the market operation, and consequently polices the behavior of the nonregulated transmission-owning companies In addition, each region has its own regulatory body, which determines the policies affecting regulated service.

Australia is unique among the countries we investigated in allowing the ownership of transmission by both regulated and unregulated entities. Regulated companies own most of the transmission, but Australia also allows merchant transmission companies, and at least one such company, TransEnergie Australia, operates in the country. The transmission tariffs of the regulated transmission companies are based on marginal costs. The transmission prices of unregulated companies are market based.

The regulated Australian transmission-owning entities are obligated to undertake planning. In addition, these companies are required to expand/improve the transmission grid, and certain incentives are offered for these activities.

The structure of the Australian transmission system has been in a state of flux and continues to evolve. The experience of TransEnergie Australia is too brief to offer any generalizable experiences. However, the future evolution of the transmission organizations in Australia, particularly the proliferation of merchant transmission lines may provide useful lessons for other jurisdictions.

Chile

Chile led the restructuring of electricity systems as the first country in the world to introduce competition and customer choice in 1982. The salient characteristics of the Chilean transmission system are presented in Table 4.

Table 4: Summary of the Salient Characteristics of the Transmission System in Chile

Ownership	There is a single entity, TRANSELEC, that owns a major part of the transmission system; the rest is the property of generators and large industrial consumers. There are no restrictions on transmission ownership.
Transmission tariff	There are two charges: • Tariff based on the forecasted marginal costs (indexed nodal prices) • An additional charge based on the so-called influence area
Ownership obligations	To provide nondiscriminatory access and service to all customers (independent of their size)
Transmission planning requirements	No systematic planning is done, and no entity in the country has responsibility for planning transmission.
Investment incentives	Nodal price differences and the contributions that the customers make
Means of recovery of new investment	Through the money collected from the tariffs and the contributions that some customers make; the customers' contributions must be repaid over time in some negotiated fashion.
Role of customers in transmission system expansion	Very important because if they are interested in an expansion of the system they can finance it, at least in part.
Regulatory body	Comisión Nacional de Energía (CNE)

In Chile, ownership and operation/control are totally separated. Ownership of the transmission grid is in the hands of a for-profit entity, and operation/control of the system is in the hands of the ISO Centro de despacho económico de carga (CDEC), which also has responsibility for operation of the electricity markets.

The CDEC transmission tariff embodies some economic efficiency properties because the rates are based on marginal costs. However, these costs are forecasted values and do not necessarily represent actual operating conditions. There are no economic signals in the Chilean system that provide incentives to expand/improve the transmission grid. Therefore, the Chilean experience seems to be of limited value and applicability for other jurisdictions.

England and Wales

The privatization of the Central Electricity Generating Board in 1990 brought about widespread restructuring of the electricity sector in England and Wales. A salient characteristic of restructuring was the establishment of the Power Pool. The introduction of the New Electricity Trading Agreement (NETA) in March 2001 effectively replaced the Power Pool and introduced major reforms to the transmission sector.

The National Grid Company (NGC) was established as a regulated, for-profit entity with responsibility for ownership and operation/control of the transmission grid and the Power Pool. Transmission system characteristics in England & Wales are summarized in Table 5.

NETA introduced specific new incentives for NGC to invest in new transmission. NGC is subject to PBR under the so-called RPI-x scheme. Included in the NGC's responsibilities is the acquisition and supply of the uplift service, which includes ancillary services, loss compensation, and congestion management. NGC acquires these services from the connected generators and pays for them out of the revenues it receives from its customers. Under the current regulatory scheme, these uplift charges are controlled. NGC has full responsibility for planning of transmission and, as part of this responsibility, issues an annual Seven Year Statement, which describes in detail the most up-to-date plans. NGC is also responsible for all investment in expanding/improving the transmission system. The investments made by NGC may be recovered through savings in uplift costs. Under the price cap regulation regulation, NGC may keep part of its uplift cost savings as additional profits. Consequently, savings in short-term operational expenses that reduce uplift costs provide incentives for long-term investment in transmission. This incentive scheme is a very important model to study for possible adoption in other jurisdictions.

The NGC incentive scheme for reducing transmission service uplift went through several revisions, reflecting accumulated experience with forecasting and controlling uplift costs. In the latest round of revisions prior to the establishment of NETA, NGC argued that the risk profile for transmission service uplift overruns was asymmetric because the likelihood that transmission service uplift costs would increase was greater than the likelihood that they would decrease. NGC also claimed that progressively tightening the targets did not allow the company to realize in successive years the reward for efforts made in earlier years, which reduced the incentives for measures (i.e., investment) that have multi-year paybacks. The regulator saw some merit in these arguments and also agreed that as transmission services uplift is reduced, a saturation effort sets in and it becomes progressively harder to achieve further reductions. On the other hand, because NGC is acquiring greater experience in securing reductions, the regulator determined that the company should be less vulnerable to risks of higher uplift. Consequently, an incentive scheme was adopted that allows NGC to retain 50 per-

Table 5: Summary of the Salient Characteristics of the Transmission System in England & Wales

Ownership	The National Grid Company (NGC) owns most of the grid in England and Wales. In addition, NGC is the operator of the entire grid, including parts not owned by NGC. Each transmission owner must obtain a license.
Transmission tariff	The transmission pricing used by NGC is based on average zonal marginal costs in the 14 zones of the grid. In addition, there is a fixed charge that is paidby all users of the grid. The regulatory body imposes a price cap for the tariff charged by NGC (performance-based regulation).
Ownership obligations	To operate, maintain, develop, and provide an effective electricity transmission service
Transmission planning requirements	The national grid has to publish annually the Seven Year Statement, which provides a forecast of the generation, demand, and transmissions plans. This document is subject to regulatory approval. NGC is in charge of the planning and expansion of the transmission system.
Investment incentives	NGC receives incentives through capped uplift charges; because expansion/improvement of the transmission system may reduce some uplift costs, NGC may use part of the realized savings as additional profits but must also absorb part of cost overruns.
Means of recovery of new investment	Through the money collected from the transmission system rates and the money collected from uplift charges
Role of customers in transmission system expansion	The transmission customers pay for the expansion through the modified transmission rates.
Regulatory body	The Office of Gas and Electricity Markets (OFGEM)

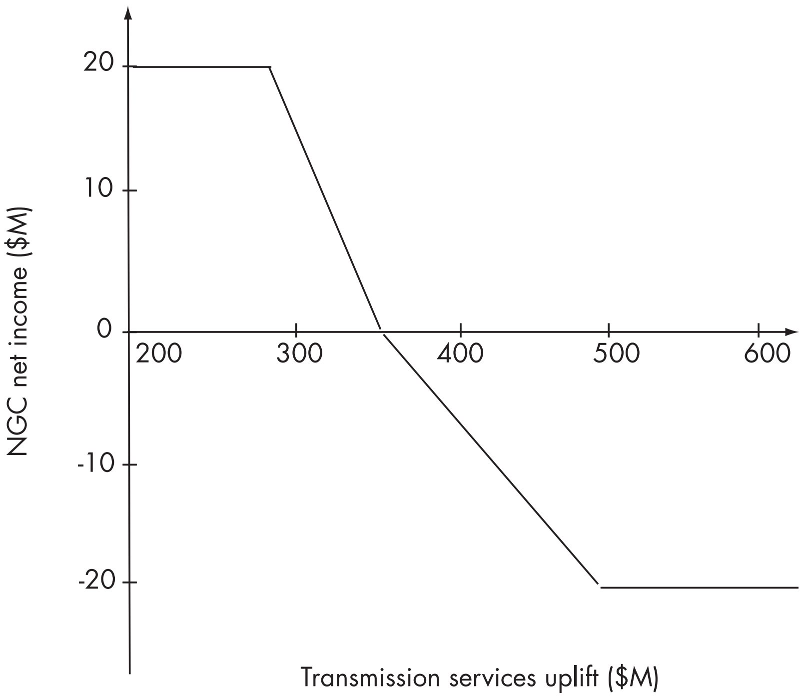
cent of uplift savings relative to the target and requires it to absorb 25 percent of any increase in uplift above the target. Furthermore, “caps and collars” were superimposed on these sharing factors, which limited NGC’s risk to large variances from the target but also removed its incentive to reduce the uplift outside that range.

This transmission service uplift scheme was employed in 1998/99 with a target of $355 million and for 1999/00 with a target of $350 million. Both profits and losses were subject to a limit of $32.9 million in 1998/99 and to $34.2 million in 1999/00.[11] For the year 2000/01, the target was lowered to $322 million whereas the “cap and collar” were set to $34 million. The structure of this incentive scheme is illustrated in Figure 1.[12]

[11]In addition, NGC received extra income of about $1.5 million in 1998/99 and $0.75 million in 1999/00 to cover certain operating and capital costs.

[12]Hanney, Alex. EEE Limited (London, UK) Private communications. (November, 2001)

Figure 1: The NGC Transmission service uplift incentive scheme for 1998/99 and 1999/00



The target transmission service uplift was charged to the Power Pool[13] on a prorated daily basis (i.e., the annual quantity was divided by 365). During the year, as cumulative performance against the target became apparent, the daily amount was adjusted according to the sharing factors and the "caps and collars." The daily amounts were allocated among the settlement periods and charged to retailers on a load-share basis. Similar incentive schemes were applied to reactive power uplift and transmission losses. The success of this incentive scheme is evident Table 6, which shows a continuous decline in uplift charges (NGC 1999).

Table 6: NGC uplift charges and incentives from 1993 to 1998 in $ millions

	1993	1994	1995	1996	1997	1998
Transmission service uplift	813	633	422	412	360	337
Reactive power uplift	94	88	87	87	87	71
Transmission losses	-	-	-	229	211	212
Incentive payment to NGC	0	45	41	16	17	16

Norway

The development of a competitive commodity market in electricity in Norway has been accompanied by a deliberate and detailed regulation of the market framework by Norwegian regulatory authorities. There is strong regulation of the rights and the duties of the TSP, which is the state-owned company Statnett. Norway has chosen the TSP model, combining transmission ownership with execution of the operation/control function. The salient characteristics of Norway's transmission system are summarized in Table 7.

So far the Norwegian regulator has not prescribed any specific reliability security standard such as the loss-

[13]This description, which is given as an example of PBR, reflects the situation in the UK prior to NETA, which came into effect in mid 2001.

Table 7: Summary of the Salient Characteristics of the Transmission System in Norway

Ownership	Statnett, a state-owned company, owns about 85 percent of the national grid; 15 percent is owned by about 20 other entities.
Transmission tariff	Every user has to pay a charge, the so-called point tariff, which consists of three components: • An energy charge reflecting the value of marginal losses, • Another energy charge reflecting the costs of constraints, and • A residual element for cost recovery.
Ownership obligations	To provide nondiscriminatory access and service to all customers (independent of their size)
Transmission planning requirements	Stattnet makes a five-year forecast of all projects, and the regulatory body has to approve the projects that will be executed. Statnett and the regional grid company are in charge of planning the expansion of the transmission system
Investment incentives	The existing tariff and, for the case of radial expansion, the contribution made by the future user of the expansion
Means of recovery of new investment	Through the money collected from the tariff and through the contributions that some customers make
Role of customers in transmission system expansion	They can make contributions to financing the expansion of the system (radial lines only).
Regulatory body	Norwegian Water Resource and Energy Administration (NVE)

of-load-probability threshold, which is specified, for instance, in England and Wales. Instead Statnett has been given the responsibility to ensure "satisfactory" reliability of electricity supply and to promote a smoothly functioning electricity market with transport capability adequate for meeting market needs. More recently, Statnett was also given the responsibility for the generation/demand balance for the short and long term. The Norwegian regulator penalizes any supply interruption.

Although Statnett is not the only transmission owner in Norway—there are more than 20 owners—Statnett owns about 85 percent of the transmission grid and is interested in becoming the sole owner. The transmission grid is already operated as an integrated system with a system-wide tariff.

Statnett has responsibility for the planning necessary to ensure a sound and reliable system. Although Statnett does not have a monopoly on the construction of new lines, it is expected to take care of any needed reinforcements if regional transmission owners are not willing to expand their systems. Statnett is spearheading efforts to increase utilization of the existing system and is investigating various means to increase transfer capabilities in order to avoid or postpone major investments in new facilities. The regulatory rules require Statnett to operate, utilize, and expand the system in a way that is consistent with the needs of society.

Loss factors in the transmission tariff give incentives affecting the operation and location of generation development. Congestion management methods partly give financial incentives for increased utilization or reinforcement (counterflow trading) and partly reveal the costs to society of transmission congestion (market splitting with different area prices). The Norwegian regulator implemented revenue-cap regulation in 1997 by defining the maximum income level for grid owners. This level is reduced annually based on the regulatory assessment of grid owners' efficiency improvements. The level is also increased annually by a percentage equal to half the energy-transport growth rate. Any reductions in costs are profits to the transmission owners. Unfortunately, this scheme provides poor incentives for investment in new transmission. Nevertheless, the transmission system in Norway has operated smoothly and facilitated highly competitive electricity markets in Norway and in the interconnected NoodPool countries (Norway, Sweden, and Finland).

Summary Remarks Regarding International Experience

Among the systems examined, Norway's appears most successful to date. The combined ownership and operation/control vested in Statnett has resulted in reliable operation of Norway's transmission grid.

The applicability of the Norway model to other jurisdictions may be limited, however, for historical reasons and the unique manner in which the market in Norway has evolved. Although there are certain incentives for improvement/expansion of the Norway transmission system, they seem to be insufficient for driving new investment; instead, the large penalties that may be assessed against Statnett in case of supply interruption are far more potent than these incentives in driving the grid owners to invest in expansion/improvement. Unfortunately, the command-and-control approach of the Norway regulator is not consonant with the competition in its electricity markets. There is a markedly insufficient economic signal from the compensation scheme for new transmission investments. As a result, the need to adopt a more market-oriented scheme for transmission in Norway persists. It is expected that the transmission framework will be revised when it is reevaluated in 2002.

The incentive scheme in England and Wales may be the most appropriate paradigm for adoption by other jurisdictions. The existence of economic signals such as those given by the uplift charges collected by NGC may be useful models for creating effective incentives for expanding/improving the transmission grid. Such incentives coupled with effective PBR are worthy of further study.

The restructuring of the U.S. electricity industry has been accompanied by the advent of new players in the

For-Profit Transmission Companies and Merchant Transmission Projects in the U.S.

transmission arena—for-profit, transmission-only companies and merchant transmission projects. These new investment vehicles have been launched to showcase the critical role of transmission in the electric power business. This section briefly describes the American Transmission Company (ATC), which started operations on January 1, 2001, as an example of a for-profit, transmission-only company, and the Neptune Project of the Neptune Regional Transmission System LLC as an example of a major merchant transmission project.

ATC was created as the result of legislation enacted by the state of Wisconsin. The company owns transmission facilities in Wisconsin, Michigan, and Illinois with book value in excess of $500 million and is the first for-profit, transmission-only company to operate in more than one state. ATC was formed through the transfer of assets primarily from investor-owned utilities and capital contributions by public-power entities. The latter have fractional ownership of the company. As electric transmission is ATC's only business, its only profits are through its earnings on transmission assets.

The company became a member of the Midwest ISO (MISO), the not-for-profit RTO in the region where ATC operates. It expects to make money by providing transmission for its customers using its existing and planned facilities. ATC can make money only by saying "yes" to customer requests for transmission capacity. Its expected construction budget of more than $100 million per year for four years is quite large for a company of its size. The company wishes to take advantage of the fact that a transmission-only company can spread the costs of new construction over a greater portion of the area that will benefit from the new construction. The company expects to develop and receive FERC approval for new products for its customers. It remains to be seen whether the incentives established by the regulators will allow the company to meet its goals of ensuring cost-effective reliable transmission to all its customers with appropriate earnings for its investors.

The past two years have witnessed the proposal of several new independent speculative (merchant) transmission projects. The three most prominent are: the TransEnergie U.S. Ltd. 26-mile DC underwater cable joining Connecticut and Long Island; the 4,800-MW high-voltage direct current (HVDC) Neptune Project connecting Atlantic Canada with New England, New York, and PJM; and the expansive TransAmerica Grid project to link mine-mouth coal-fired plants in Wyoming to load centers in the Chicago and Los Angeles regions through DC lines. The Neptune Project is probably at the most advanced stage and will be used below to illustrate the key aspects of a merchant transmission project.

The basic thrust of Neptune is to connect generators in areas with plentiful supplies to loads in large metropolitan areas. The project aims to exploit the resource and load diversity of the interconnected regions and to strengthen the interconnections between the New York, New England, and PJM grids. In effect, the Neptune Project would become an integral part of the emerging Northeast RTO envisioned by FERC. The Neptune Project's May 23, 2001 filing with FERC detailed the four-phase staging of this ambitious DC submarine-cable-based grid network. The filing requested FERC's approval for the proposed open-access tariff at negotiated rates following an open-season approach to capacity reservation (FERC Docket No. ER01-2099-000). The July 27, 2001 FERC Order accepted the tariff subject to certain conditions. FERC required all Neptune Project capacity to be subject to the open-season approach to capacity reservation and thereby put an end to the project's proposed set-aside of 30 percent of capacity for bilateral negotiations. The project was mandated to join an RTO and use the RTO's tariff. FERC's Order directs the project to work with the future Northeast RTO in the design of a tariff to integrate the project's financing needs. This is a two-sided directive because the FERC July 12 Order detailing its vision for the Northeast RTO stated unequivocally that its "long-term competitive goals are better served by RTO expansion plans that allow for third-party participation as well as merchant projects outside the plan." FERC directed PJM to develop revised procedures so that "third parties may participate in constructing and owning new transmission facilities." The FERC directive clearly puts out a welcome mat for merchant transmission projects.

The July 27, 2001 FERC Order dealt a death blow to the project's request to include compensation in the tariff for system benefits on the existing transmission system. However, negotiations with the future Northeast RTO may result in compensation for the increase in available transfer capability in the existing network resulting from the new facilities if the parties can design the RTO tariff to explicitly or implicitly accommodate this compensation. The project will know the stream of revenues it may expect once the open season for capacity reservation is completed.

The FERC open-door policy for merchant transmission may considerably change the nature and structure of the transmission grid in the U.S. Unless carefully crafted initiatives/policies are formulated, the grid may face the threat of Balkanization. This threat could result in opportunistic expansion along the profitable paths while neglecting the reliability of the remaining grid. Such "cherry picking" reduces the investment incentives for investors willing to undertake a more comprehensive regional expansion plan. Steps will be required to ensure that commensurate improvements of the other parts of the grid are undertaken so no grid customers are disadvantaged.

"Straw Man" Business Models

Two of the business model variations described in the section "The Range of Options of Business Models," on page C-4, represent the main advantages of the separate ownership and control and joint ownership and control approaches. The nonprofit ISO that controls assets owned by regulated TOs represents the business model that currently prevails with separate control and ownership of transmission assets. At the other extreme is the for-profit ITC. These two models have been at the center of the national debate concerning the preferred business model for RTOs. Much of that debate has not been specific about the key weak points of each model:

- The nonprofit ISO model implemented in several systems in the U.S. lacks a market-based mechanism to attract transmission investment. In fact, the California ISO has just issued a contract for the development of methodology for market-based evaluation of transmission investment proposals.
- Most characterizations of ITCs allude to PBR schemes but do not specify details.

The subsections below present "straw man" versions of these two business models for the purpose of fleshing out the possibilities inherent in the separate ownership and control and combined ownership and control organizational structures.

Nonprofit ISO Controlling Transmission Assets Owned by Regulated TOs

This section describes two variants of a business model in which a nonprofit ISO operates and controls the transmission assets owned by TOs and manages congestion in real time by dispatching balancing energy resources using a security-constrained, bid-based economic procedure. These variants roughly represent the designs implemented at PJM and ERCOT, with the addition of a mechanism for fostering market-based transmission investment. Under these models, users of scarce transmission resources who schedule energy transactions through the ISO are charged a real-time congestion fee that represents a "scarcity rent" for the use of these resources. That scarcity rent also reflects the incremental cost of relieving congestion through counterflow, which results from dispatch of generation resources out of merit (i.e., dispatching more expensive energy ahead of less expensive energy). In principle, any congestion problem has a "generation solution," which amounts to creating counterflow on the congested interface, and a "wires solution," which requires investment in transmission assets. From an economic perspective, the optimal amount of transmission capacity is achieved when the marginal cost of the generation solution and that of the wire solution are equal. This equality represents the optimum solution from a social perspective, i.e., the total of consumer and producer surplus is maximized; however, there is no guarantee that the consumer surplus increases at this solution. Transmission capacity mitigates market power, so it is possible that additional capacity may benefit consumers by facilitating trading and reducing energy prices although such investment need not be optimal from a total welfare perspective. It is also possible that a transmission expansion that is socially desirable may disadvantage some consumers by increasing their energy costs.[14]

In current nonprofit ISO structures, the ISO has responsibility and authority for transmission planning, but the investments are made by the TOs. The ISO can order a TO to build transmission facilities and has the authority to evaluate and authorize construction of facilities proposed by investors. These planning and evaluation activities are predominantly driven by reliability considerations. Investments in new transmission assets that are approved by the ISO are transferred to ISO control and receive compensation on a regulated-rate-of-return or cost-of-service basis in the same way as is true for existing facilities. The funds required for compensating TOs are collected by the ISO through the sale of transmission rights, congestion charges, connection charges, and energy-based uplift charges.

We explore next the options for economics-based transmission investment in the context of a nonprofit ISO. The basic idea in an economics-based transmission investment paradigm is that efficient investment in capacity[15] is aimed at reducing scarcity of capacity resources up to the point at which the socially optimal capacity level is achieved and such investments can still be financed by scarcity rents. Hence, all we need is to establish a system of property rights to the transmission system and a mechanism that will allow investors in new capacity to collect the appropriate scarcity rent for that capacity. Then, investors will have the incentive to put up the capital for capacity expansion and the scarcity rents that they will collect will be sufficient to finance that investment as long as the wires solution is more economical than the generation solution.

Consider a simplified world with no externalities where a transmission line connecting two locations could be expanded in small increments by adding individual fibers to the line. If the capacity of the line is scarce, users will be charged a congestion fee. By adding fibers to the line, the investment results in increasing the flow and would be entitled to collect the congestion fee for the additional flow. As long as that revenue exceeds the financing cost of the capacity expansion, investors are motivated to add more capacity. However, as more capacity is added, scarcity rents may drop until the rent for shipping another MW of power across the transmission line exactly covers the financing cost for adding one more MW of transmission capacity. Because the scarcity rent reflects the marginal cost of dispatching energy out of merit in order to relieve congestion on the line, the level of capacity at which the congestion rent exactly covers the financing costs is also

[14]An example of this possibility is described in the Issue Paper, *Transmission System Operations and Interconnection,* by F. Alvarado and S. Oren.

[15]We use the word "capacity" loosely; capacity refers to an increase in the transfer capability of the transmission system.

the socially optimal capacity level at which the marginal cost of a wires solution equals the marginal cost of a generation solution. Clearly, under this scheme it is never socially optimal to add transmission capacity to the extent that it will eliminate congestion completely even though that might be desirable from the perspective of facilitating trade and mitigating market power.

In the next subsections, we apply the above principles of economics-driven capacity expansion in the context of two variants of nonprofit ISO operation.

The nodal pricing/forward financial transmission right approach (the PJM model)

In this variant, the ISO operates an energy spot market where locational marginal energy prices are based on a security-constrained, bid-based, optimal dispatch. Congestion charges for a point-to-point transaction are priced at the opportunity costs given by the locational price difference between the two points. Point-to-point forward financial transmission rights (FTRs) take the form of financial instruments that entitle their holders to the locational price difference times the number of rights (in MW units) over the specified time interval. This instrument is *equivalent* to a physical right because it enables its holder to execute a point-to-point transaction and offset the congestion charges with the FTR revenues. FTRs are auctioned off by the ISO periodically for different time horizons. The FTRs that are issued must satisfy simultaneous feasibility conditions, which require that if all FTR holders were to use their rights by scheduling corresponding transactions, these transactions would be feasible without impacting the security of the system. This simultaneous feasibility condition guarantees that the congestion revenue collected by the ISO can cover the FTR settlements.

An idealized market-based approach to transmission investment can be implemented within the above framework by simply awarding transmission investors an appropriate number of FTRs that will reflect the enhancement provided by their investment.[16] These awards can capture all the external effects of the expansion. Awarding the investor a portfolio of FTRs that reflects the incremental transfer capabilities between the different nodes can accomplish this goal. If the transfer capability between some pairs of nodes has been reduced by the expansion, the corresponding FTRs must be taken off the market and the market value of those FTRs debited from the investor's award. If the investment is socially efficient (i.e., it costs less than a generation solution to the congestion problem it solves), the settlement income of the awarded FTRs should provide sufficient funds to finance the investment. The portfolio of FTRs that represents the increase in transfer capabilities of the grid from expansion of even a single line is not unique. Hence investors may be allowed to choose the FTR portfolio that provides them appropriate compensation for their investment.[17]

The above approach may work for relatively small incremental investments that will not have a major impact on the market value of the FTRs. Its major shortcoming is that is does not correspond to the reality of transmission investments, which are lumpy. The incremental addition of fibers, while a useful metaphor to explain the concepts involved, is unrealistic. The addition of capacity will likely eliminate the congestion as well as the congestion rents that are supposed to provide the income stream to finance the investment. The effect of lumpiness and the perceived risk associated with a cash flow resulting from FTR settlements may discourage investors from accepting FTRs in lieu of a stable income stream. Thus, major investments in transmission will

[16]This description follows the work of Hogan (1999), who articulates this approach and the resolution of some obvious shortcomings in detail.

[17]The details of such a procedure are described by Bushnell and Stoft 1996.

still require regulatory approval and some form of cost-based rate-of-return regulation. Nevertheless, even if FTRs cannot serve as an investment compensation, FTR market prices provide important market signals for transmission investment and should be taken into consideration in transmission planning activities.

An interesting, although potentially controversial, resolution to the lumpiness problem has been proposed by Hogan (1999), patterned after the treatment of patents and intellectual property. This scheme would allow investors in transmission to withhold a portion of the capacity they install for a limited time period to maintain an "optimal" level of congestion that will sustain the market value of the FTR they obtain and thus allow them to recover their investment costs. This scheme is similar to the approach used in awarding patents on drugs, which allows drug companies to collect monopoly profits during a limited time period in order to recover R&D costs. Implementing such a scheme would be relatively easy. The investor would instruct the ISO about the capacity the investor wishes to release to the ISO, and the ISO would adjust the constraint it uses in its economic dispatch algorithm accordingly (effectively derating the line). The investor would get FTRs only for the capacity released. The investor would not have an incentive to abuse the system and withhold more capacity than needed to recover the investment cost because such excessive withholding might result in higher FTR values that may attract additional investment, and that would undermine the investor's objective of maximizing profits. At least in theory, an investor would be motivated to release to the ISO what would have been the optimal amount of capacity expansion absent the lumpiness issue.

The zonal pricing/flowgate approach (the ERCOT model)

The wide variation in real-time nodal prices resulting from security-constrained, bid-based economic dispatch can often be traced to a small number of constrained elements in the transmission system, referred to as flowgates.[18] Although the above observation may be true at any point in time, it is debatable to what extent flowgates are persistent and predictable. The congestion management system adopted in California and by ERCOT and under consideration in some emerging RTOs is based on the premise that most congestion occurs at a limited number of predictable bottlenecks. If this premise is reasonable, then it is possible to design a pricing system based directly on the marginal value of the individual congested facilities and a corresponding system of property rights with respect to these facilities. This approach, sometimes called the "flowgate" rights (FGR) approach, is dependent, however, on knowledge of the Power Transfer Distribution Factors (or PTDFs).[19] Under this scheme, transmission users schedule transactions with the ISO, and the ISO employs incremental and decremental energy bids to relieve congestion and meet security constraints at least cost. Transmission users are charged a congestion fee based on the fraction of their scheduled transaction that flows on the designated commercially significant constraints (CSCs). The charge per MW flow on a CSC is set to the shadow prices (i.e., marginal value) on capacity of the CSCs ,which reflects a scarcity rent. These shadow prices are also equal to the marginal cost of relieving congestion on the CSC through deployment of balancing energy to produce counterflow. For the case of radially connected flowgates, this model leads naturally to a zonal pricing structure. For other cases, it is equivalent to a nodal pricing system unless a zonal approximation is created for the resulting prices.

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[18]Even one congested element may result in different prices at every node in the system.

[19]For a detailed discussion of the flowgate approach to congestion management, see Chao, Peck, Oren, and Wilson (2000).

Transmission rights take the form of flowgate rights which are rights, denominated in MW, that entitle the holder to a payoff equal to the shadow price on the corresponding CSC. In most cases, it is quite simple to define these rights as directional rights (i.e., they have value only if transmission capacity is scarce in the designated direction of the right). A user of the transmission system can fully hedge the congestion fee for a transaction by holding a portfolio of FGRs that reflects the distribution of flow on the CSCs induced by the transaction. It that case, the FGR settlement revenue exactly offsets the congestion fee.

Capacity expansion in this variant of the nonprofit ISO business model (implemented in Texas and California) is based on a planning and approval process run by the ISO and driven by considerations of reliability. The ISO can order capacity expansion and has the authority to approve investments proposed by TOs. Approved investments are compensated through a cost-based, regulated rate of return.

Applying the market-based transmission investment paradigm in the FGR is context would be simpler than in the nodal pricing case because for the FGR approach the externalities have been priced out. The shadow price on a CSC reflects exactly the marginal value of adding one MW to the flow limit on that CSC. Consequently adding one MW of capacity to a CSC can be directly rewarded with a one-MW FGR on that CSC, and the income from that FGR covers the financing of the incremental investment as long as the investment is socially efficient. An investment is deemed inefficient when the shadow price reflecting the marginal value of the incremental capacity or equivalently the marginal cost of producing counterflow through procurement of balancing energy exceeds the amortized investment cost for expanding the capacity of a CSC. Incidentally, because the FTR (full nodal) pricing system is fundamentally equivalent in its valuation structure to the FGR approach, a corresponding analysis can be performed for the FTR case.

As in previous examples, a major obstacle to market-based investment is the lumpiness of capacity expansion projects, which prevents investors from being able to exactly gauge the appropriate amount of transmission expansion so that the FGR revenues pay off the financing costs of the project. The FGR prices provide a useful market signal for capacity expansion that should be taken into consideration in planning and evaluating investments; however, regulatory intervention is needed to guarantee an appropriate return on investment. The alternative of allowing withholding of the capacity for a limited time horizon so that investors can recover their investments through FGR settlement revenues applies here just as in the FTR case.

It is worth noting that FTR and FGR become identical in the case of a radial AC system or a controllable DC transmission link between two nodes. In both cases, the entire flow resulting from a point-to-point transaction moves through the line. One may interpret FGR as an attempt to treat the expansion of a transmission interface as if it were a merchant DC expansion for the portions of the flow that go through that line. However, unlike the case of controllable DC merchant lines, there is no one-to-one correspondence between the added capacity and the increased point-to point transfer capability. A trader would need to acquire FGRs on multiple lines impacted by the trader's transaction in order to be hedged against congestion charges. Therefore, a merchant investor in a nonradial AC interface cannot finance investments by directly selling capacity on its merchant line as is the case for the Neptune and TransEnergy projects described on page C-25.

The For-Profit ITC

Although no for-profit ITCs exist in the U.S. to date, several proposals have been developed in response to FERC Order No. 2000. In this model, we envision a company of sufficient regional scope to internalize many of the externalities associated with its transmission operations. The ITC owns or leases and operates most of its transmission resources.[20] The ITC is independent (as spelled out in the FERC Order No. 2000) of any generator, wholesale energy trader, or distribution company, and it operates as a regulated monopoly responsible for transmission operations, maintenance, and investment. Such an ITC would typically be created by divestiture of facilities from one or more vertically integrated utilities to form an independent company. If a single company divests all its transmission assets, the process of setting up the ITC is conceptually simple, akin to any divestiture except that the value of the assets will be determined by existing and anticipated regulation, and the divestiture itself will require regulatory approval. In the U.S., the more likely scenario is that several utilities would divest their transmission assets to form an ITC.[21]

Whether the assets of an ITC are divested from a single company or from multiple owners, their valuation depends on the regulatory rules regarding rates, profits, and any operational constraints imposed on the ITC. The key issue here is that the vertical integration of ownership and control internalizes some of the externality between investment and operation. This enables the regulator to devise a reward scheme that appropriately reflects the output of the ITC, i.e., the transmission service it provides, rather than the costs of its assets. As indicated earlier, it is unlikely that an incentive scheme can be devised that induces the ITC to selfishly produce a set of operating rules that are consistent with FERC's open-access orders and with social efficiency objectives. The regulatory regime imposed on the ITC determines the constraints it faces and its profitability. ITC regulation must be compatible with FERC's Orders Nos. 888 and 2000 and provide incentives and constraints that will induce the ITC to operate the transmission network to foster efficient short-term energy markets. It should also be compatible with the financial viability of the ITC and with long-term incentives for the ITC to invest in and maintain the transmission network.

The goal should be to move ITC regulation toward a performance-based approach; this goal can be approached in an evolutionary manner, starting with an ROR strategy that will evolve into PBR. The ROR phase can provide a training ground for the subsequent PCR phase in which price caps can be benchmarked against the immediately preceding ROR regime. Initially, the PCR might include constraints on the allowed rate of return in the form of profit-sharing bands. Over time, as the ITC and the regulator develop a better understanding of the risks involved, these profit-sharing bands can be relaxed until they disappear altogether, leaving the price cap to assure proper incentives and reasonable consumer dividends.

Whether under ROR or PCR, the ITC can offer more than one service, and each service may have a complicated cost structure. Thus, the ITC needs flexibility to change individual prices to accommodate changing customer needs, subject to an overall profit or price constraint. For this straw man business model a price

[20]This model follows closely the ITC vision articulated in Awerbuch, Hyman, and Vesey (1999) and Awerbuch, Crew, and Kleindorfer (2000).

[21]In California, for instance, the recent electricity crisis provided a golden opportunity for the formation of an ITC. There was discussion about the state purchasing the transmission assets of PG&E and Southern California Edison to provide these companies cash that would enable them to pay off their debts.

structure that consists of a three-part tariff, as described by Awerbuch, Crew, and Kleindorfer (2000) has the components:

- A fixed access charge, levied on loads. This charge depends on the system's ability to offer access (capacity) to customers. Such a charge gives the company an incentive to add customers or capacity in the most economical manner because these factors increase access charge revenues and are not a return on rate base.
- A MW-based priority injection rights fee or congestion charge, levied on generators. The revenues from this charge can be used to help manage congestion. These fees do not go to the ITC but are used as offsets against access charges, which eliminates a potentially perverse incentive for the ITC to perpetuate congestion in order to collect more congestion fees.[22]
- A MWh throughput charge levied on loads for each MWh delivered. This reflection of system usage provides the ITC with incentives to use its assets more efficiently. This charge may be varied by node, zone, time of day, etc. to better reflect the marginal costs of transmission.

By properly adjusting the weights between the access and energy charges in the price cap formula and accounting for regulatory lag between adjustments, it is possible to provide incentives to the ITC to make the investments necessary to relieve congestion. This classic PBR approach has been employed in the telecommunications industry. The basic principle is that it is more profitable for the firm to meet its price

Options

cap through usage revenues than through access revenues. This creates an incentive for the firm to relieve congestion in order to increase transaction volume on the transmission network.

In the preceding sections, we examined a variety of alternative business models for transmission and issues associated with these models. One important message that emerges from this examination is that there is no perfect business model for transmission. The "best" model in any given situation depends on the ownership structure and regulatory environment that form the context for the creation of the transmission entity. Therefore, rather than prescribing particular models, we define ultimate goals that could be selected to guide short-term actions and set an agenda for change in transmission business models. The options we outline below are not mutually exclusive but are intended to emphasize different key points.

Option 1

Move toward regional consolidation of transmission assets under the control of for-profit regulated independent transmission companies that will be subject to PBR and will have the authority and responsibilities

[22]The details of this scheme are described in Deng and Oren (2001).

of an RTO, including the planning and financing of new transmission investment. This option may require legislative initiatives to empower FERC to order divestiture of privately owned transmission assets and enable the divestiture of transmission assets owned by public power entities, including federal power authorities and municipal utilities. It would also require modifications to the existing statues to exempt transmission assets funded through tax-free bonds from private-use rules.

Option 2

Initiate congressional legislation and tax reform that will enable publicly owned transmission assets including those owned by federal power authorities and municipalities to be put under the full operational control of RTOs for unrestricted commercial use. Empower the RTOs to plan, authorize, and order transmission expansion and finance this expansion through a federally mandated, energy-based surcharge.

Option 3

Initiate organic growth of independent transmission companies by spinning off transmission assets owned by federal power authorities (e.g., TVA) to form the core of a voluntary transmission-owners consortium that would operate as a for-profit ITC, subject to PBR and with the authority and responsibilities of an RTO. The profit share resulting from the federally owned transmission assets can be channeled into the federal power authority. This option would still require congressional legislation altering the mandate of the federal power authorities and relevant tax reforms.

Option 4

Have nonprofit RTOs operate transmission assets that have multiple owners. Investment and innovation would be left opportunistic, with merchant DC and AC transmission-expansion initiatives subject to approval by the RTO. Merchant investment would be financed through transmission rights issued by the RTO as entitlements to congestion rents or to physical capacity. Additional investment for expansion needs identified by the RTO could be solicited and financed on a cost basis through rate increases, subject to state regulation. A federal energy surcharge (similar to a gasoline tax for financing highway construction) can provide an alternative financing mechanism for RTO-initiated transmission expansion subject to FERC approval. (This option is closest to the current situation in the U.S.)

Summary and Conclusions

This paper describes the issues that must be considered in adopting a business model for a transmission service provider. Many dimensions must be accounted for, and there is an ongoing debate, in the context of FERC's RTO initiatives, over the merits of competing models. The key issues that distinguish the models are whether or not control and ownership of transmission assets are vertically integrated and whether the TSP operates as a for-profit or nonprofit enterprise. The two extremes that have been the focus of the ongoing debate are the nonprofit ISO that operates transmission assets owned by regulated transmission assets owners and the for-profit regulated ITC that owns and operates transmission assets. With few exceptions, most of the material previously written on this topic advocates one model or another. This paper delineates the issues involved in the variations on these two general models, describes a broad range of options, and presents the pros and cons of the alternatives based on positions expressed by experts on both sides of the debate. The paper also reviews approaches that have been adopted in other countries and the resulting experiences. The fundamental question remains: what is the best way to provide incentives and finance investment in the transmission system, which has not kept up with the generation sector and the increased demands for transmission services resulting from restructuring of the electricity industry in recent years.

Of the various options for business models described in the previous section, Option 4 is the closest to the current state of affairs. Unfortunately, reliance on merchant expansion alone is unlikely to produce sufficient investment in transmission, and cost-based remuneration of new investment fails to adequately recognize the risks perceived by investors.

The fact that even a relatively large increase in transmission investment would result in modest increases in customers' electricity bills while having great potential benefits for efficiency, reliability, commerce, and mitigation of market power suggests that we should err on the side of overinvestment in transmission to enhance trade and increase system reliability. Such investment should therefore be encouraged through PBR that offers incentives for additional capacity by allowing the investor to share in the value added by such capacity to the system in terms of improved reliability and increased trading. Such an approach can only be implemented when operation and investment are controlled by the same entity, which can profit from the added value. A scheme like that found in the UK, which allows the transmission company to share in the gain from reducing congestion uplift cost. This type of scheme could not be implemented when congestion management is under the control of a nonprofit RTO that passes congestion costs through to consumers and neither bears any of the cost of capacity expansion nor shares in any benefits from congestion reduction.

It is the authors' opinion that Option 1 presents the most promising business model to serve the transmission sector in the long term since it is amenable to performance based regulation and enables compensation of transmission assets based on their value rather than cost. Option 2 is a partial but necessary step toward achieving the goals of Option 1, and Option 3 is less desirable because of its limited scope but could represent a pragmatic starting point that would enable us to experiment gradually and on a limited scale with the

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Transmission Planning and the Need for New Capacity

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Introduction

The U.S. electricity industry is in the midst of a transition from a structure dominated by vertically integrated utilities regulated primarily at the state level to one dominated by competitive markets. In part, because of the complexities of this transition, planning and construction of new transmission facilities are lagging behind the need for such grid expansion.

Between 1979 and 1989, transmission capacity increased slightly faster than did summer peak demand (Hirst and Kirby 2001). However, during the subsequent decade, utilities added transmission capacity at a much lower rate than loads grew. The trends established during this second decade are expected to persist through the next decade. According to one analysis, maintaining transmission adequacy at its current level might require an investment of about $56 billion during the present decade, roughly half that needed for new generation during the same period (Hirst and Kirby 2001).

Expanding transmission capacity requires good planning (as well as appropriate market rules and regulatory oversight). The Federal Energy Regulatory Commission (FERC 1999) emphasized the importance of transmission planning in the creation of competitive wholesale markets. FERC wrote that each regional transmission organization (RTO) "must be responsible for planning, and for directing or arranging, necessary transmission expansions, additions, and upgrades that will enable it to provide efficient, reliable, and non-discriminatory transmission service and coordinate such efforts with appropriate state authorities." FERC included transmission planning as one of the eight minimum functions of an RTO:

> [T]he RTO must have ultimate responsibility for both transmission planning and expansion within its region that will enable it to provide efficient, reliable and non-discriminatory service… . The rationale for this requirement is that a single entity must coordinate these actions to ensure a least cost outcome that maintains or improves existing reliability levels. In the absence of a single entity performing

> these functions, there is a danger that separate transmission investments will work at cross-purposes and possibly even hurt reliability.

This shift from planning conducted by individual utilities for their system to meet the needs of their customers, to planning conducted by RTOs to meet the needs of regional electricity markets, raises important issues (Table 1). These issues include the criteria for planning (reliability, economics, etc.); environmental considerations (effects of transmission expansion on the location and types of emissions from power plants, accommodation of remotely located renewable resources, as well as the direct siting and environmental effects of transmission); economic development (providing greater access to cheaper power may encourage local and regional economic growth); the role of congestion costs in deciding which projects to build; the consideration of generation, load, and transmission-pricing alternatives to new transmission projects; the economic and land-use benefits of building larger facilities ahead of immediate need; the role of new solid-state technologies that permit operation of transmission systems closer to their thermal limits; the role of merchant transmission projects; and the growing difficulty in obtaining data on new generation and load growth caused by the separation of generation and retail service from transmission. Finally, collaborative transmission-planning processes, which include various stakeholders early in the process (e.g., as problems are being identified rather than when solutions have already been selected), should be considered as RTOs plan for future regional electricity needs.

Part of the complexity associated with transmission planning stems from transmission's central position in electric-system operations and wholesale power markets. Because of its centrality, transmission serves many commercial and reliability purposes. American Transmission Company (2001) identified several objectives for transmission planning and expansion: improve transfer (import and export) capability from different directions, accommodate load growth without delay, accommodate generation development without delay, provide flexibility to transmission customers to modify their transactions as market conditions change, reduce service denials and interruptions due to transmission constraints (equivalent to reducing congestion costs), cut losses, and improve reliability. Southern Company Services (1995) mentions many of the same objectives and also includes provision of sufficient margin to permit transmission elements to be taken out of service temporarily for maintenance.

The American Transmission Company (2001) plan notes some of the many issues it will have to consider as it plans for transmission expansion, including public involvement in the planning process, minimizing environmental and land-use impacts, timely licensing and construction of good projects, and balancing the robustness of the transmission system with the need to keep transmission rates reasonable.

The foregoing comments on the purposes and complexities of transmission planning emphasize the fact that such planning is only one element of a broader process that ultimately leads to the construction of needed bulk-power facilities (Fig. 1). To assess various transmission and nontransmission (generation, load, and pricing) alternatives, transmission models require large amounts of data and projections related to loads, generation, and transmission. Transmission planners use detailed electrical-engineering computer models to assess these alternatives (Fig. 2). Model results, combined with information on project costs, environmental effects, siting, and regulatory requirements, lead to financial and regulatory assessments of different projects. Ideally, these plans lead to the construction of needed projects, cost recovery (including a return on investment) for transmission owners, and transmission rates that appropriately charge users for the services they receive.

Table 1. Key transmission-planning issues

Topic	Issues
Reliability vs commerce	To what extent should RTOs plan solely to meet reliability requirements, leaving decisions on grid expansion for commercial purposes (e.g., to reduce congestion costs) in the hands of market participants?
Congestion costs	Are congestion costs (e.g., short-term nodal or zonal congestion prices and long-term firm transmission rights) a suitable basis for deciding on transmission investments?
Alternatives to transmission	What role should RTOs play in assessing and motivating suitably located generation and load alternatives to new transmission? Should RTOs provide information only or should they also help pay for such alternatives?
Economies of scale	Should RTOs or private investors overbuild transmission facilities in anticipation of future need to reduce the dollar and land costs per GW-mile of new transmission facilities? How should these economies be balanced against the possibly greater financial risks of larger transmission facilities?
Advanced technologies	What are the prospects for widespread use of new technologies (e.g., superconductivity, solid-state electronics, and faster systems to collect and analyze data) to improve system control, thereby permitting operation of existing grids closer to their limits?
Planning data	Who will provide the data needed for transmission planning, particularly on the locations, timing, and types of new and retiring generating units and the loads and load shapes of retail customers?
Economic effects	How should transmission's impact on regional power prices and the resulting impact on the regional economy be factored into transmission planning?
Environmental and other societal effects	How should the effects of transmission availability on the generation mix and the resulting shift in emissions be included in transmission planning? How should remotely located generators (e.g., coal and wind) be accommodated in transmission planning? Should transmission be built to increase fuel diversity for generation and to discipline generator market power? How should potential siting problems be incorporated into the planning process?
Centralized vs decentralized transmission planning and expansion	To what extent can private investors, rather than RTO planners, decide on and pay for new transmission facilities? Can they, in spite of network-externality effects, capture enough of the benefits of such transmission projects to justify their investment? How can new technologies advance private investment?

Figure 1. Transmission-planning models, and their inputs and outputs.

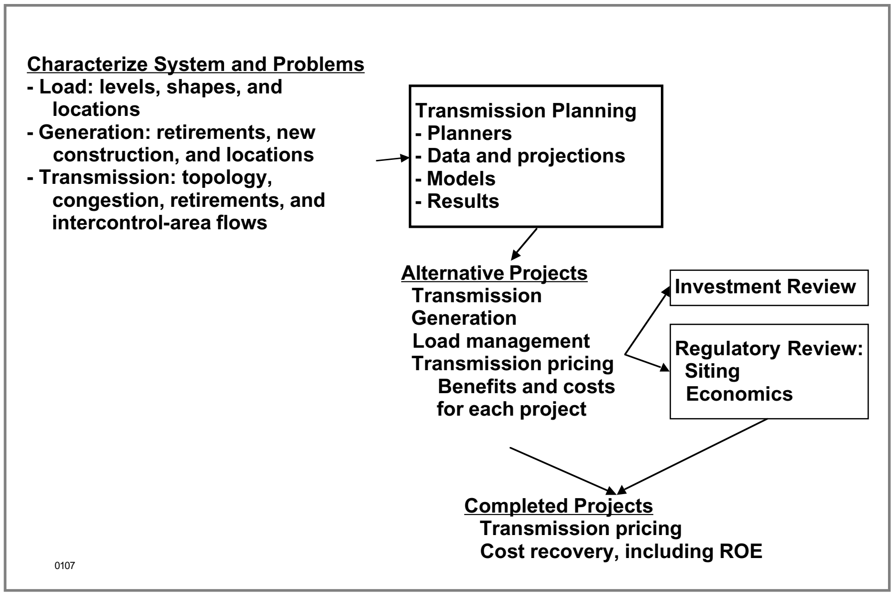


Fig. 2. The relationship between transmission planning and its inputs (data and projections) and results.

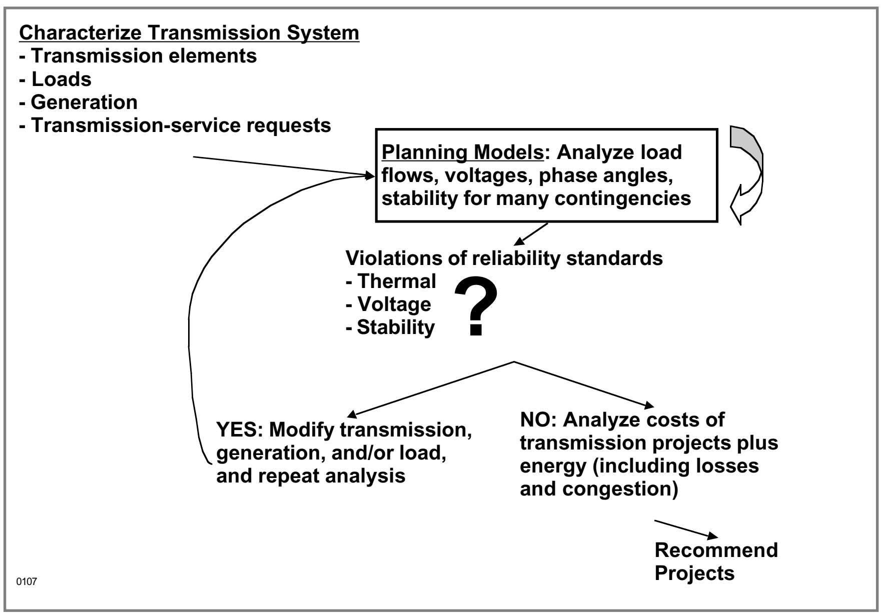


Figure 2 expands on the transmission-planning portion of Fig. 1. This second figure shows how load-flow, dynamic, and short-circuit models are used to determine whether the bulk-power system can meet all the applicable operating and planning reliability standards. The arrow to the right of the box labeled Planning Models indicates that these models are run over and over to test the ability of the bulk-power system to operate within specified ranges for all first- and some multiple-contingency conditions.

The fundamental characteristic that makes transmission planning and investment so difficult is lack of control of the grid and the inability to control the flow through individual transmission elements (e.g., lines and transformers). (Devices such as phase shifters and direct current (DC) links allow control, but are much more expensive than traditional transmission facilities.) Each transmission element is part of a network that is a common resource available to all. Because electricity flows according to the laws of physics and not in response to human controls, what happens in one part of the grid can affect users throughout the grid. Because of these large externalities, transmission must be centrally managed and regulated. Other characteristics that complicate transmission planning include:

- Large Geographic Scope—Conditions on one part of an alternating current (AC) network affect flows throughout the network. Consequently, transfers between any two points on the network can be restricted by constraints elsewhere in the network. Similarly, upgrades to any part of the network affect transfer capabilities throughout the network.

- Diversity of Interests—Each transmission enhancement affects many market participants. Generators will either expand their market opportunities (if they are low-cost producers) or reduce their market opportunities. Loads have similar, but opposite, interests.

- Transmission vs Generation—The split and differences between competitive generation and regulated transmission affect transmission planning. The competitive generation business encourages faster planning, shorter deployment times, and less sharing of commercially sensitive information. The regulated transmission business environment produces slower planning and longer deployment times (to accommodate an inclusive public process) and the wide sharing of information. In addition, transmission and generation are both complements and substitutes. As a consequence, poor transmission planning and inefficient transmission expansion could undercut competitive wholesale markets and increase electricity costs.

- Long Life—Transmission is a long-lived (30 to 50 years), immobile investment with very low operating costs. The need for new transmission shows up in real-time congestion prices. It is difficult to accurately forecast the need for a specific transmission investment for several decades. The generation and demand-side alternatives are often shorter lived and have higher operating costs that can be eliminated if the investment is no longer needed.

- Regulatory Decision Process—Because the regulator (and the regulated entity) are spending ratepayer dollars, public processes are used to produce good decisions. All opinions and options are welcome and considered, which can lead to a time-consuming and costly process.

- Regulatory Uncertainly—Investors are unlikely to spend their money until it is clear that they will recoup their investment and earn a reasonable return on that investment.

- Environmental Impacts—Some people oppose new transmission lines (and, to a lesser extent, substations) on aesthetic grounds or because they might lower property values. Others are concerned about the health effects of electromagnetic fields. Although little scientific evidence supports this concern about transmission lines, public perceptions and fears may lead to opposition to construction of new transmission lines (National Institute of Environmental Health Sciences, 1999).

The remainder of this issue paper is organized as follows: The next section summarizes planning processes as practiced by vertically integrated utilities and today's independent system operators (ISOs). This section also summarizes the planning processes proposed by RTOs. Subsequent sections outline the characteristics of an ideal transmission plan and planning process; a benchmark against which current and future plans might be assessed; and several key planning issues and the complications that arise because of the increasing competitiveness and transitional state of the U.S. electricity industry. A later section recommends certain actions for DOE, FERC, and others on improved planning processes; while the final section summarizes the key findings from this issue paper.

Transmission Planning Practices

Traditional Utilities

Historically, transmission planning was much simpler than it is today and than it is likely to be in the future. Until the mid-1990s, the U.S. electricity industry featured vertically integrated utilities. As a consequence, transmission planning was closely coupled to generation planning. Utilities, because they owned generation and transmission, could optimize investments across both kinds of assets. With respect to operations, utilities routinely scheduled generation day-ahead and redispatched generating units in real time to prevent congestion from occurring. The costs of such scheduling and redispatch were spread across all customers and reflected in retail rates.[1]

In addition, utilities had good data and forecasting tools to estimate current and future loads and generating capacity. Because each utility was the sole provider of retail electricity services, it had considerable information on current and likely future load levels and shapes. Because each utility was the primary investor in new generation, it had considerable information on the timing, types, and locations of new generation and corresponding information on the retirement of existing units.

Finally, the amount of wholesale electricity commerce was much less than it is today and it was much simpler. It was simpler in the sense that most transactions involved neighboring utilities, either to take advantage of short-term economies of operation or for long-term purchases of firm power.

Current Planning Environment

In today's electricity industry, generation and transmission are increasingly separated, either through functional unbundling of these activities or through corporate separation. This deintegration, combined with the competitive nature of electricity generation, makes it much harder for transmission planners to coordinate

[1]Although transmission planning focused primarily on generation and loads within a single control area, the tight power pools and regional reliability councils reviewed utility plans to ensure that projects proposed in one service area would not adversely affect other utility service areas.

their activities with those of generation owners. In particular, the owners of generation are reluctant to reveal their plans for new construction and retirement of existing units any sooner than they have to.

In some regions, today's system operators are independent of load-serving entities. Therefore, the system operators have little information on the details of retail loads, such as the types of end-use equipment in place and trends and patterns in electricity use. It is now the load-serving entities that have such information, and for competitive reasons, they may be reluctant to share such information and projections with the system operator.

This deintegration of generation and transmission means that congestion management is no longer an internal matter. Of necessity, congestion management involves a system operator, transmission owners (if different from the system operator), power producers, and load-serving entities.

The separation of generation from transmission can lead to investment decisions in both sectors that are suboptimal from a broad societal perspective. For example, more than 8000 MW of new generating capacity plan to interconnect to the Palo Verde substation in Arizona (Emerson and Smith, 2001). But the existing transmission system can handle no more than 3360 MW of new generation. Even with the three new 500-kV lines proposed for this area, the maximum export capability will be only 6750 MW because of stability limits, well below the 8000 MW planned. To make the problem even worse, most of these new generators will obtain natural gas from the same pipeline. Thus, the outage of this pipeline could become the single largest contingency in Arizona, increasing greatly the amount of contingency reserves that must be maintained.

Finally, the amount and complexity of wholesale electricity commerce is much greater than it was a few years ago. Transactions today can span several control areas, and ownership of the power may change hands several times between the point of injection (the generator that produces the power) and the point of withdrawal (the load that consumes the power). This complexity makes it difficult for system operators to know the details of transmission flows and even more difficult to project what these flows might be like in future years.

Review of Recent Plans

Independent System Operators (ISOs) and utilities are developing transmission-planning processes to accommodate the needs of a rapidly evolving and increasingly fragmented electricity industry. This section briefly reviews several plans recently issued by ISOs and other regional entities.

The Electric Reliability Council of Texas (ERCOT) (2001) plan discusses historical and projected generation and load by region within ERCOT, including a range of projections. These projections form the basis for an identification of existing and likely future transmission constraints within the Interconnection and of an assessment of the need for additional transmission. The ERCOT report includes a discussion of existing transmission capacity and expansion possibilities for each of the three ERCOT subregions.

Overall, the ERCOT plan identifies six major transmission constraints (generally thermal limits, but sometimes stability limits). The plan also identifies several projects intended to mitigate these constraints. These projects include several 345-kV lines (both new lines and additional circuits on existing towers), a static compensator (to provide dynamic reactive-power support), and capacitors (to provide static reactive-power support). In addition, the transmission owners proposed several projects, which ERCOT recommended for construction.

One indication of the success of the ERCOT transmission-planning process is the number of transmission projects recently completed or under construction. ERCOT has several transmission advantages over other regions, including regulation by a single entity (the Texas PUC), a state government that supports additional transmission, and a regulatory system that gives transmission owners a reasonable assurance that their capital investments will be recovered. Of the seven projects considered critical during the past few years, one was completed in 2000, five are on schedule to be completed by the end of 2002, and one is undergoing further evaluation (Texas Public Utility Commission 2001).

The goals of the Mid-Continent Area Power Pool (MAPP) (2000) plan are to ensure that the transmission system can "reliably serve the load indigenous to the MAPP region,… provide sufficient transfer capability to reliably accommodate firm transfers of power among areas within MAPP and between MAPP and adjacent reliability regions, and provide an indication of transmission costs for enhancing transfer capability and relative costs for alternative locations of new generation." The MAPP process is bottom up, with plans developed by individual transmission owners, then integrated for each of the five subregions, and then integrated again at the MAPP level. In addition, considerable analysis is done for the MAPP region as a whole, primarily to analyze projects that span more than one subregion. The MAPP review ensures that projects proposed in one subregion will not adversely affect the electrical system in other subregions. Although MAPP planning still relies heavily on the individual utilities, the regional planning process is beginning to significantly influence the individual expansion plans.

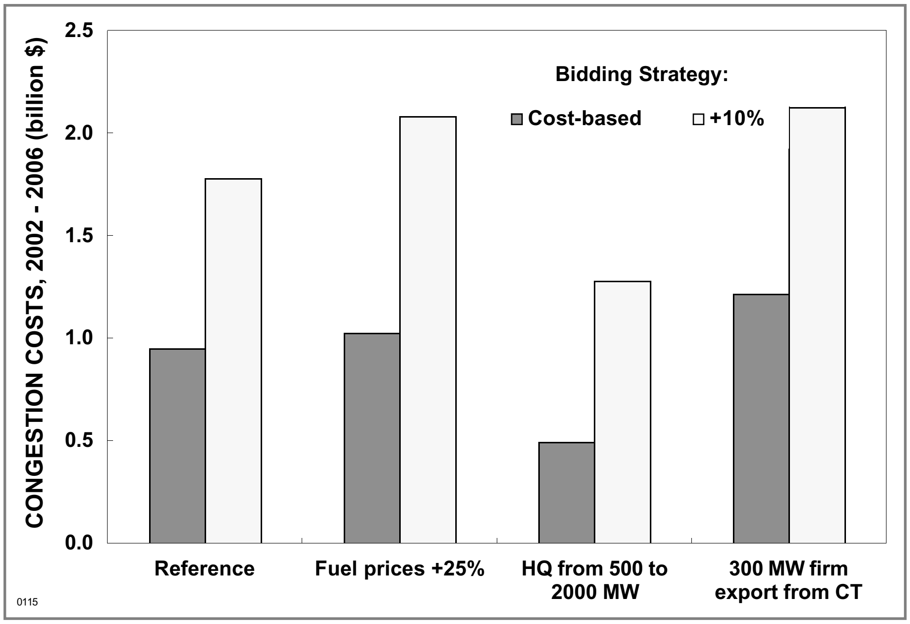
The MAPP plan uses information on transmission service requests that were refused along with data on transmission curtailments to help in the analysis of "desired market use of the regional and inter-regional transmission system." These data "provided strong evidence to indicate that transmission constraints to the east of MAPP significantly hampered electrical sales" (Mazur, 1999).

The ISO New England (2001) plan breaks new analytical ground. This plan explicitly analyzed the potential benefits of new transmission from reductions in congestion through what the ISO calls its Projected Congestion Cost Assessment, "which, through modeling, determined the economic costs associated with transfer limits between regions and separately analyzed the New England system on a bus by bus basis for transmission constraints." As the report notes, "Significant transmission congestion will exist from an economic viewpoint, primarily between ME/NH [Maine and New Hampshire] and Boston, SEMA-RI [Southeast Massachusetts] and both Boston and SWCT [Southwest Connecticut]. Estimates of New England congestion range between approximately $200-$600 million per year during the study period, depending on the assumptions utilized."

The New England analysis also considered the effects of market power on congestion costs, which could have enormous effects on the benefits associated with new transmission facilities. Because analysis of strategic market behavior is difficult, the New England analysis used a simple approach: it increased the bid prices for all generators by 10 or 25% above their marginal operating costs.[2] This approach may underestimate the

[2]The traditional assumption in production-costing models that generators bid their marginal costs is almost surely incorrect. On the other hand, appropriately simulating bidder behavior, with and without new transmission that expands the scope of regional markets and reduces congestion, is very difficult.

Figure 3 Congestion costs in New England under different assumptions about fuel prices, Hydro Quebec imports, and exports from Connecticut, as well as the bidding behavior of generators.



benefits of transmission in reducing the ability of generators to exercise market power.

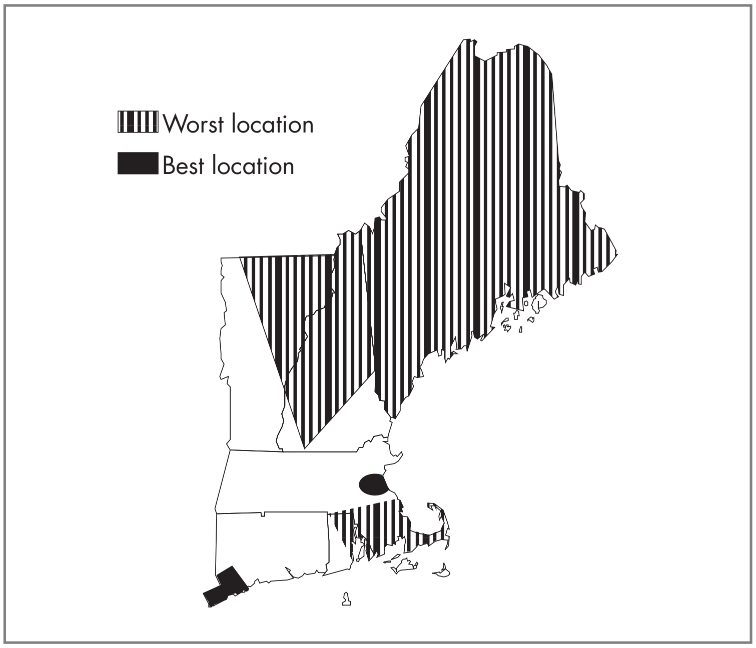
Figure 3 is a summary of some of the congestion-analysis results developed by ISO New England. The graph shows how sensitive these estimates are to different assumptions. And this is just a subset of the cases ISO NE examined; the 5-year congestion costs for the full set of cases ranged from about $500 million to more than $3 billion. Because this was just an initial assessment, it includes no estimates of the costs to build the transmission needed to relieve congestion in the region.

ISO New England divided the region into 13 subareas based primarily on transmission characteristics and constraints: "The subareas have been defined solely based on transmission interfaces that are relevant to both reliability and congestion concerns." These subareas do not necessarily conform to political or utility boundaries.

National Grid USA (2000) owns some of the transmission assets in New England. Its report is less a detailed plan for New England and more an overview of likely transmission needs in the future. The report examined the period 2001 through 2005 in terms of demand projections, generation, the relationship of generation to demand, transmission-system topology (major zones and interfaces), transmission performance (system power flows), capability (transfer limits and congestion costs), and transmission-system opportunities.

The chapter on opportunities is especially interesting because it shows where within New England new generator interconnections "would alleviate or exacerbate congestion on the transmission system." As Figure 4 shows, locating generators in Boston or southwest Connecticut would relieve congestion, whereas locating generators in Maine, northern Vermont or New Hampshire, Rhode Island, or southeastern Massachusetts would worsen congestion. Information like that shown in Figure 4 should help guide market decisions on new generation and load-management programs, as well as possible merchant-transmission projects. Provision of information on the current and expected future state of the transmission system and the costs of using that system could reduce what North American Electric Reliability Council (NERC) (2001) sees as "inefficient transmission expansion [caused by the] uncoordinated siting of generation and the development of transmission projects."

Figure 4 National Grid USA's assessment of the best and worst locations within New England to locate new generating units.



The initial assessment conducted by American Transmission Company (2001) divided its region into five subareas. Like ISO New England, ATC defined these zones on the basis of transmission "system topology, load characteristics, load density and existing generation." ATC plans to revise the boundaries of these zones if and when bulk-power flows and conditions change. Its initial plan presents several proposals for transmission additions within each zone for 2002, 2003, 2004, and between 2005 and 2010, based on load-flow simulations conducted for 2002, 2005, and 2010.

The Western Governors' Association (2001) issued a conceptual plan for the Western Systems Coordinating Council. The plan is conceptual in that it looked at broad regional needs and not at local transmission needs. The report noted important limitations in current transmission plans and the associated planning processes:

> The current transmission planning process is fragmented, based on utilities' individual forecasts of needs and specific interconnection requests from new generation.
>
> At best, coordination occurs on a subregional basis. The current planing process is reactive, rather than forward looking. There is a wide gap between evolving merchant needs on the resource side (regional) and existing grid plans (local or sub-regional) on the transmission side. Planning assumptions are based primarily on local traditional resources and give little consideration to remote and non-conventional resources.

This western analysis considered two generation scenarios to the year 2010. One involves gas-fired generation built close to load centers and the other includes coal, wind, geothermal, and other generation located in remote areas. In the first scenario, little new transmission is needed between 2004 and 2010. In the second case, transmission investments of $8 to $12 billion are needed to support 23 GW of new remotely located generation.[3]

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[3]This works out to a transmission investment of more than $400 per new kW of remote generation, a very high cost. If new coal and wind generation costs about $1000/kW, the supporting transmission would add 40% to the initial cost. By comparison, the new transmission planned for the Pennsylvania-New Jersy-Maryland Interconnection (PMJ, 2001b) region ($720 million to connect 27,500 MW of new generation) is expected to cost only $26 per new kW of generation. Part of this cost difference occurs because the distances between generation and load centers are much greater in the west than in the mid-Atlantic region.

Because the Bonneville Power Administration has built no major transmission facilities since 1987, it has a substantial backlog that it is now addressing (VanZandt, 2001). Experts from eight electric utilities in the Pacific Northwest reviewed the first nine projects that BPA proposed, at a total cost of $615 million (Infrastructure Technical Review Committee, 2001). This largely qualitative review examined, for each of the nine projects, the limiting outages to be addressed by the project, the expected local and regional benefits from the project, various risks associated with the project, a project description, and alternative transmission projects that could address the limiting outages. The review also includes an appendix on risk and uncertainty that outlines the kinds of risks facing new transmission projects, including adequacy requirements, congestion relief, changes in electric-industry structure, and over- vs under-building.

Some recent plans are more limited in scope than the ones discussed above. Often, the plans do not fully integrate planning for reliability with planning for commerce. Because some entities have received so many generator-interconnection requests, their plans are dominated by the specific projects required to connect these new generators to the grid. Correspondingly, the plans do not anticipate possible problems that might occur in the future as a consequence of load growth; generator retirements; other new generators being built within the control area; or additional bulk-power transactions into, out of, or through the control area. In particular, these plans generally do not provide sufficient guidance to market participants on desirable locations for new generation, load-reduction programs, or merchant transmission. These plans are more reactive than proactive, in part because transmission planners do not have enough time to develop plans that look out several years and offer guidance on where to locate new generators. Instead, the planners are often overwhelmed with requests for new generation interconnections. The Bonneville Power Administration (BPA, 2001) wrote:

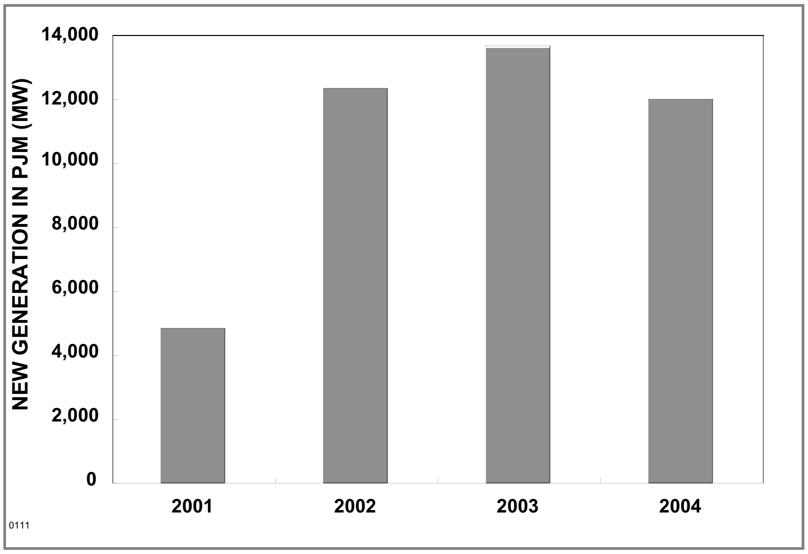
> BPA has received requests for transmission integration studies for more than 13,000 megawatts of new generating capacity at sites around the Northwest. More are pouring through the door. In just the last two weeks, BPA has received eight formal requests for studies on integrating new combustion turbines totaling 3,850 MW. … The Transmission Business Line is informing developers that it will take at least nine to 12 months to complete the required studies.[4]

As of March 2001, PJM had received more than 250 generator-interconnection requests, organized into seven queues. The first five queues include 40 GW of new generation to be completed between 2001 and 2004, enough to add more than two-thirds to PJM's current generating capacity (Figure 5). Similarly, ISO New England had, as of Spring 2001, a queue with 40 GW of new generation, far more than the region's peak demand of 23 GW.

Perhaps because of the many interconnection requests PJM has received, its plan, although massive in length and detail, appears to lack any overall purpose. The plan includes two baseline assessments, the first of which analyzes compliance with regional reliability standards from 2001 through 2006 assuming no new generating units are built. The second baseline plan examines, in a similar fashion, the years 2002 through 2007 assum-

[4]The Tennessee Valley Authority faces a similar situation. It has received applications from independent power producers for 90,000 MW of new generation, more than three times the amount of existing generation (Whitehead, 2001). TVA would need an extra 50 system planners to clear the backlog of interconnection studies associated with all these new generators.

Figure 5 Planned generating capacity in the PJM area.



ing all new generation in Queue A[5] is built. Separately, PJM presents all the interconnection studies associated with the new projects in Queues A, B, and C. In August 2000, the PJM Board approved the Queue A construction projects, with an estimated cost of $300 million; in June 2001, the Board approved the projects in Queues B and C, estimated to cost an additional $420 million.

This review of recent transmission plans shows tremendous variation. No single plan encompasses all the elements of a good transmission plan, as discussed in the section on Proposed Planning Process. Several factors explain the lack of key elements in many plans: (1) the dramatic changes in the U.S. electricity industry raise new issues for transmission planning, (2) the data and analytical tools to address these new issues have not yet been developed, (3) the ISOs are new entities that are still expanding their staffs, (4) the authority and responsibilities of the ISOs and other regional entities are not yet clear, and (5) the planning staffs are very busy responding to generator-interconnection requests. NERC (2001) recently noted that "these complex and rapidly evolving requirements are overwhelming the transmission planning process such that there is not enough time to develop optimal transmission plans."

Review of RTO Transmission Planning

The RTO filings of October 2000, required by FERC's Order 2000, pay little attention to Function 7 on transmission planning and expansion. The need to resolve other RTO issues—such as governance, regional scope and membership, and transmission-cost allocation and revenue requirements—dominated the prefiling deliberations. Perhaps because of these factors, FERC (1999) gave the RTOs three years after becoming operational to meet the requirements of Function 7.

The GridFlorida (2000) Planning Protocol calls for an "open and inclusive process" conducted by the RTO and supported by a Transmission Planning Committee that will provide "advice and input regarding the planning process" to the RTO. The protocol deals with regional planning; local planning; generation interconnection; data bases; standards for planning, design, and construction; transmission construction; and the role of reliability organizations and the Florida Public Service Commission in the planning process.

[5]PJM sorts generator interconnection requests into queues depending on when the request was formally made. The August 2001 PJM plan includes Queues A, B, and C, with a total of 27,500 MW of new generation. Although the use of queues may be fair to generators, its application is controversial because it may increase overall electricity costs. For example, some merchant generation projects, although far down in the queue, might help solve transmission problems and, from a societal perspective, should be expedited.

Although the GridFlorida proposal says much about the planning process, it contains few details on the substance of what a transmission plan should contain. While the protocol mentions "market solutions" it does not define the term and does not explain how they are to be identified, assessed, and implemented if found to be cost effective. Similarly, the protocol mentions "alternative solutions" but does not indicate what these alternatives might be, how they are to be compared with transmission solutions, and how they will be implemented.

The RTO West plan (Avista Corp. et al., 2000) "anticipates that RTO West's approach [to transmission planning] will evolve over time." The initial plan anticipates transmission expansion for two purposes: (1) "for reliability of service to load" and (2) "to relieve congestion." As noted elsewhere in this paper, distinguishing between reliability and commercial needs for new transmission is very difficult and perhaps a distraction. With respect to relief of congestion, RTO West anticipates a "market-driven expansion mechanism," which, in principle at least, should reduce the need for RTO West to develop its own plan in this area.

Attachment P (Description of RTO West Planning and Expansion) focuses on decision-making authority: who decides what facilities are to be built and who pays for these investments. The Attachment commits RTO West to develop:

> (1) criteria to be applied by RTO West in determining the level of transfer capability that should be maintained from existing facilities, (2) transmission adequacy standards, (3) further definition of the market-driven mechanism [for transmission expansion], (4) the [new-transmission-cost] allocation procedure, including objective criteria, (5) interconnection standards, and (6) the details of the relationship/participation of RTO West with appropriate interconnection-wide and regional reliability organizations.

The Alliance RTO (American Electric Power Service Corp. et al. 2000) proposal is included in its Attachment H: Planning Protocol. The RTO is responsible for "coordinating" the planning rather than for doing the planning itself. (Some might question whether a "coordinated" plan is truly an integrated, regional plan or merely a collection of plans prepared by individual transmission owners.) The RTO's Reliability Planning Committee will be "the vehicle through which coordinated reliability planning activities will be conducted." RTO staff and representatives from each transmission owner and local distribution utility will be members of this committee, but not other market participants. This committee will be responsible for the planning models and data, reviewing and approving planning studies, determining the need for system expansion to meet reliability needs and transmission-service requests, participating in NERC and regional reliability processes, and coordinating transmission planning and expansion with other RTOs. The committee will produce a 10-year plan every year. The RTO's Planning Advisory Committee "will provide a forum for stakeholders and interested parties to have input in the planning process." With respect to transmission projects intended to reduce congestion, the Alliance RTO "will encourage market-driven operating and investment actions…."

The proposal from the New England Transmission Owners et al. (2001) builds on the experience with ISO New England. It envisions a binary RTO with a nonprofit ISO and a for-profit independent transmission company (ITC). The proposed three-phase planning process "combines the knowledge and objectivity of ISO-NE

[ISO New England] with the strengths of an investor-owned business focused on transmission…." The process consists of the following steps:

- The ISO will lead a needs assessment, which will integrate data and projections on regional loads, generation (existing, planned retirements, and potential additions), transmission, and inter-control area transactions to forecast the region's needs for additional transmission. The needs assessment will be consistent with regional reliability planning standards, address congestion costs, and consider transmission-system performance.

- The ITC will develop a Regional Transmission Facilities Outlook, which will identify transmission alternatives that may be needed based on a range of plausible scenarios.

- Finally, the ISO will assess the ITC's Outlook and approve a regional plan. This assessment will consider other alternatives proposed by the ISO and stakeholders. The ISO review will provide "a check that the Outlook is not biased in favor of transmission solutions at the expense of generation or other market-based solutions." "The decision to proceed with [transmission projects] will be made by the market [participants] for market based proposals (including merchant transmission) and by the ITC for regulated transmission proposals."

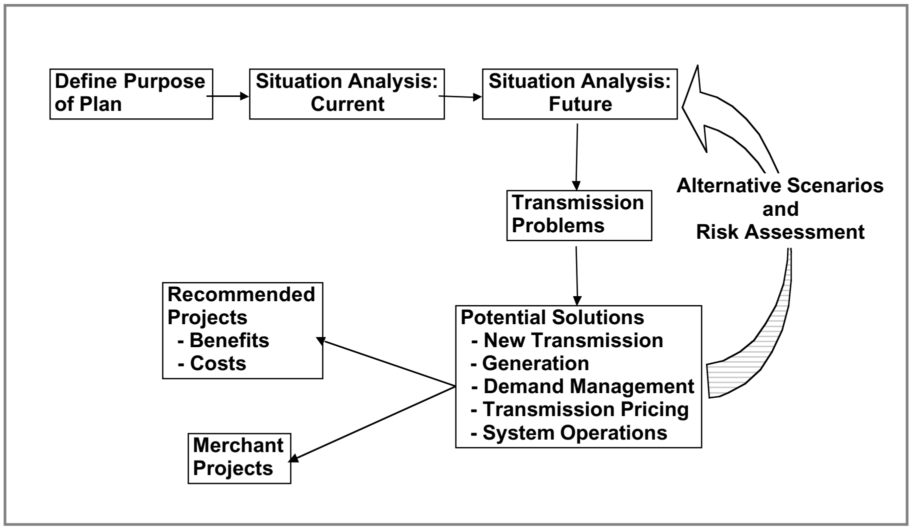
This review of some RTO filings suggests that much work remains to be done by the RTOs to develop comprehensive and meaningful transmission-planning processes. Unfortunately, progress has been slow during the past several months. One RTO posted a progress report on its website in August 2001 that its "… planning and expansion principles are still under discussion…." Deciding on a specific transmission-planning approach is difficult in some regions because the participants cannot agree on whether transmission investments should be driven by the market participants or by reliability requirements. In the former case, generator owners, large customers, and private investors might pay for new facilities built as merchant projects, while in the latter case the transmission owners (and ultimately, all retail customers), in response to RTO plans, would pay for such projects through a centralized process.

Proposed Planning Process

As noted above, transmission planning today is much more complicated, and perversely, much more uncertain, than it was several years ago. Based on our review of several recent transmission plans, we offer a suggested RTO transmission-planning process (Figure 6), the results of which should include broad consensus on new transmission and nonwires projects that are needed and that get built in a timely and cost-effective fashion.

Several of the activities summarized below are covered in greater detail in the following section. Our proposed process begins with a clear identification of the purpose of the transmission plan (Step 1), followed by a comprehensive assessment of the current regional situation, encompassing both operations and markets (Step 2). This situation analysis provides a firm basis for discussing future conditions, problems, and potential solutions. Steps 3 and 4 involve projections of likely conditions several years into the future and an identification of transmission problems that might occur under these postulated future conditions. Steps 5 and 6 assess various transmission and nontransmission alternatives that might solve the problems identified in Step

Figure 6 Outline of proposed RTO planning process.



4. Finally, Step 7 summarizes the results of the analyses conducted in the prior steps and recommends specific projects to address the transmission problems discussed in Step 4.

Step 1. What is the purpose of this transmission plan?6 Who developed it? In response to what requirements? How were various interest groups (e.g., generators, transmission owners, load-serving entities, distribution utilities, retail customers, and state regulators) represented in the development and review of this plan? How does the plan reflect the market design in that region (e.g., the number and types of markets for energy, installed capacity, ancillary services, and congestion)? How were the practical limitations of siting and project financing addressed in the plan (e.g., did the planning process consider nontechnical as well as technical issues, who will pay for transmission projects)? To what extent is the plan intended to motivate market solutions to transmission problems?

Step 2. Describe the current situation, covering bulk-power operations (both generation and transmission), wholesale markets, and transmission pricing. What problems (e.g., reliability, congestion, losses, generator market power), if any, occur that are caused by limitations in the transmission system? What transmission projects are under construction or planned for completion within the next few years to address these problems? What are the estimated costs and benefits of these projects, individually and in aggregate? What entities are expected to benefit and to pay for these projects? Explain the computer models used to analyze transmission conditions and the limitations of these models (analytical approximations).

Step 3. Describe the bulk-power system as it is expected to exist in the future (e.g., five and ten years). What are the levels, patterns, and locations of loads? Describe the region's fleet of generating units, including locations, capacity, and operating costs (or bid prices). What are the likely effects of new generation facilities on interconnection requests, the overall transmission system, and the costs of new transmission construction? What transmission-pricing methods might be used to recover the costs of capital, losses, and congestion? Describe the transmission flows within the region as well as the flows that occur into, out of, and through the region. Given the many uncertainties that affect future fuel

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[6]These purposes could include maintenance of reliability, promotion of competitive electricity markets, support for development of new generation, promotion of economic growth, creation of new jobs, and so on.

[7]The results of Steps 2 and 3 should be sufficiently detailed that other parties can assess for themselves market solutions to solve these problems (e.g., those discussed in Step 6).

prices, loads, generation, transmission and its pricing, and market rules, create various scenarios or sensitivities that can be used subsequently to analyze potential problems and transmission improvements (Steps 4 and 5).[7]

Step 4. What transmission problems, both reliability and commercial, are likely to exist given the future conditions (scenarios) developed in Step 3?[8] What other problems might exist for which transmission could be applied (e.g., generator market power caused by a restricted geographical scope of wholesale markets, limited fuel diversity caused by insufficient transmission facilities to remote locations with fuel, such as coal and wind)?

Step 5. What transmission facilities might be added to the current system to address the problems identified in Step 4? What effects would these facilities have on compliance with reliability standards, commercial transactions, losses, and overall regional electricity costs (generation plus transmission)? Can recent technological advances in transmission equipment and software be applied? Do they capture potential economies of scale associated with building (ahead of need) larger lines than currently needed? Do these proposals address the potential for generators to exercise market power in wholesale electricity markets?[9] What are the likely capital costs of these transmission additions? How do the costs and benefits of individual projects, as well as groups of projects, compare with each other? Can any of these transmission projects be built on a merchant (i.e., for profit and unregulated) basis? What kinds of risk assessment were conducted in developing recommendations on these new transmission projects?[10] How were these risks addressed in the plan, including the risks of over- vs underbuilding transmission?[11] Should certain transmission facilities be built to guide current and future decisions on the locations of new generating units and the locations and types of demand-management programs; that is, should transmission planning be proactive rather than reactive?

Step 6. What nontransmission alternatives (including suitably located generation and price-responsive load programs as well as alternative transmission-pricing schemes[12]) might be deployed to address the problems identified in Step 4? These alternatives could also include changes in system-operations, such as remedial-action schemes. To what extent can these generation, demand-side, and pricing alternatives address the problems for which the transmission facilities suggested in Step 5 were pro-

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[8]These problems could appear as real-time congestion, denial of requests for service, or curtailment of approved transactions. They could also include operational difficulties caused by aging and obsolete equipment that should be replaced to reduce forced and maintenance outages or increase functionality.

[9]It may be very difficult analytically to estimate the kinds of strategic bidding behavior that might occur. Such behavior will be a strong function of the RTO operating and market rules as well as the physical infrastructure (amounts and locations of generation, transmission, and load).

[10]Uncertainties are much greater than in the past. Today, they include load shape and levels, generator locations (new construction and retirements), market operations, market prices for energy and ancillary services, transmission pricing (including locational pricing for losses and congestion), patterns and levels of commercial transactions, weather, fuel price volatility, and new generation and transmission technologies.

[11]For example, consider the risks associated with cost recovery for a new transmission line needed to connect a new generator to the grid. This risk could be eliminated by requiring the generation owner to pay the capital costs up front rather than through rates over a 20-year cost-recovery period.

[12]Such pricing schemes should encompass access charges as well as charges for congestion and losses.

posed? What are the expected costs to the transmission system of these nontransmission alternatives (which may not reflect the total costs of these generators and/or demand-management programs)? Based on the differences in characteristics and the differences in costs and benefits, recommend either transmission or nontransmission solutions to the problems identified in Step 4. Where no solutions are offered, indicate why. (Presumably, the expected status quo should continue if the costs of solving a problem exceed the benefits of doing so.)

Step 7. Based on the foregoing analyses, recommend transmission pricing, generation-location decisions, demand-management programs, and construction of new transmission facilities. If market participants do not propose the solutions analyzed in Steps 5 and 6, recommend those transmission facilities (from Step 6) that should be built under traditional regulation. Summarize the benefits and costs of these proposed projects, both singly and in aggregate. Can the projects ultimately be approved and built in a timely fashion? Can they be financed? Will these projects be undertaken by market participants acting in their own interest, or must the RTO require their construction and ensure that customers at large pay for them?

Table 2, based on this 7-step process, identifies key ingredients of a successful transmission planning process and plan.

Table 2. Checklist of important characteristics of a transmission plan

- ❒ Public involvement throughout planning process
- ❒ Broad range of alternatives considered, including suitably located generation and demand-management programs, new transmission technologies, and various transmission-pricing methods
- ❒ Effects of transmission on generator market power
- ❒ Effects of transmission on compliance with reliability standards, both planning and operating
- ❒ Effects of transmission on congestion costs
- ❒ Comprehensive risk assessment of transmission plan(s)
- ❒ Proactive, rather than reactive, transmission plan (consideration of needs for increased throughput and locational guidance for new resources, not just responses to generator-interconnection requests)
- ❒ Development of a practical and robust, rather than a theoretically optimized, transmission plan
- ❒ Support for projects built through competitive-market mechanisms
- ❒ Timely completion of the plan

Key Transmission Planning Issues

Planning Criteria: Reliability and Commerce

Traditionally, vertically integrated utilities planned their transmission systems to: (1) meet North American Electric Reliability Council (NERC) and regional-reliability-council reliability requirements and (2) ensure that the outputs from the utility's generation could be transported to the utility's customers. (Utilities sometimes built transmission lines for economic reasons; for example, to provide access to cheaper power in a neighboring system or to export surplus power.) Today, transmission systems are called on to do much more. They must serve dynamic and rapidly expanding markets in which the flows of power into, out of, and through a particular region vary substantially over time. As a consequence, transmission planners may need to look beyond the NERC Planning Standards in assessing alternative transmission projects and also consider enabling competition to occur over large geographic regions (NERC 1997). A market-focused approach might seek to reduce the number of times transmission-service requests are denied and generation must be redispatched to avoid congestion. Where congestion (locational) pricing is used, this goal is met by reducing congestion costs (discussed below). Congestion pricing might reduce the distinction between reliability and commerce by explicitly pricing reliability.

Many industry experts believe that the distinction between reliability and commerce in transmission planning is increasingly irrelevant. Reliability problems (e.g., a line that would become overloaded during a contingency) are also commercial problems that affect different market participants differently (e.g., flows are reduced on the line in question, which means that the output from cheap generators must be reduced and the output from expensive generators must be increased). Conversely, certain commercially desirable flows may be restricted because of reliability problems that would otherwise occur. Equally important, these people believe that transmission serves a vital enabling function, permitting the purchase and sale of energy and capacity across large regions and, in the process, reducing problems associated with generator market power.

Some experts believe that the distinction between reliability and commerce is important. Not all reliability problems have commercial implications, they noted. Some local problems (e.g., low voltages close to load centers) are related more to reliability than to commerce. The solution to such reliability problems might be the addition of capacitors to serve local loads regardless of whether the generation source is near or far. The distinction may be important in determining who pays for the project, with reliability projects paid for by all grid users but commercial projects paid for only by those transmission customers who benefit from the project. Of course, deciding who does and does not benefit from a project can be difficult and contentious. The Pensylvania-New Jersey-Maryland Interconnection (PJM) (2001a) baseline plan focuses on reliability: "Transmission constraints on market dispatch are economic constraints. Economic constraints are not considered violations of reliability criteria as long as the system can be adjusted to remain within reliability limits on a pre-contingency basis."

Economies of Scale

It is generally cheaper per megawatt of capacity to build larger transmission lines (Table 3). For example, the cost per MW-mile of a 500-kV transmission line is about half that of a 230-kV line. Higher-voltage lines also require less land per MW-mile than do lower-voltage lines (right side of Table 3). A 500-kV line requires less than half the land per MW-mile of a 230-kV line.

Both of these factors argue for overbuilding lines rather than trying to size lines to exactly match current and short-term forecast needs. (Overbuilding includes the use of larger conductors, construction of larger towers that can carry more than one set of circuits, and the use of higher-voltage lines.) Overbuilding a line now will (1) reduce long-term costs by avoiding the much higher costs of building two smaller lines and (2) reduce the delays and opposition associated with transmission-line siting by eliminating these costs for the now unneeded second line.

Table 3. Typical costs, thermal capacities, and corridor widths of transmission lines

Voltage (kV)	Capital cost[a] (thousand $/mile)	Capacity (MW)	Cost (million $/GW-mile)	Width[b] (feet)
230	480	350	1.37	100
345	900	900	1.00	125
500	1200	2000	0.60	175
765	1800	4000	0.45	200

[a]These estimates are from Seppa (1999) and include the costs of land, towers, poles, and conductors. We increased these estimates by 20% to account for the costs of substations and related equipment.
[b]These estimates are from Pasternack (2001).

On the other hand, the lumpiness of transmission investments (e.g., one can build a 345-kV line or a 500-kV line but not a 410-kV line) can complicate decisions on what to build and when. Also, a large transmission line may impose more of a reliability burden on the system than do several smaller lines. Indeed, if a new, large line becomes the largest single contingency, contingency-reserve requirements might increase in the region. And, opposition might be greater to a 500-kV line than to a 345-kV line because the former line has taller towers and requires more land.

Congestion Costs

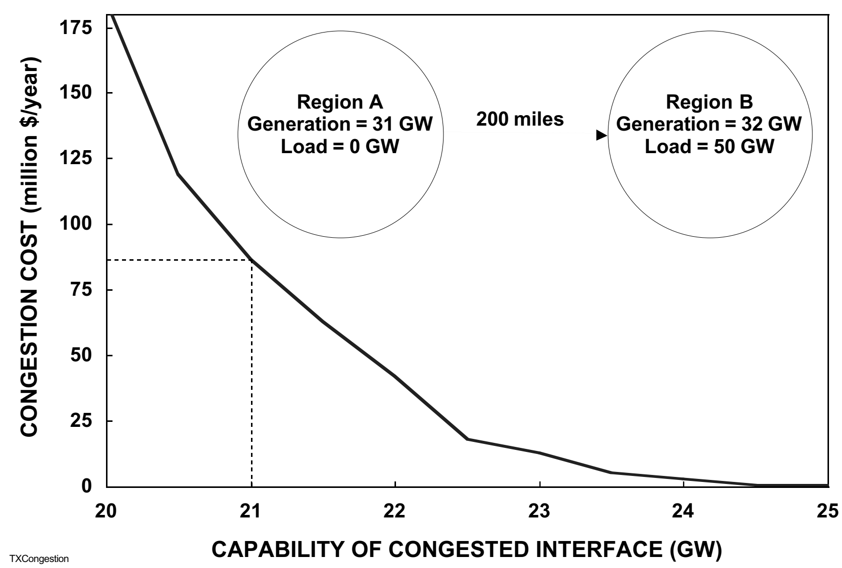
Decisions on whether to build new transmission are complicated by uncertainties over the future costs of congestion. (To some extent, the prices of firm transmission rights show how the market values certain transmission paths.) These uncertainties relate to load growth, the price responsiveness of load, fuel costs and therefore electricity prices, additions and retirements of generating capacity and the locations of those generators, the exercise of market power by some generators, and transmission pricing. The ISO New England (2001) analysis, summarized in Figure 3, shows this complexity very well. Analysis conducted for the New York ISO showed that the large number of proposed generating projects in or near New York City and Long Island "would reduce the level of congestion observed on the…bulk power system, with the biggest congestion decreases occurring in New York City and on Long Island" (Sanford, Banunarayanan, and Wirgau, 2001).

We developed a simple hypothetical example to explore these issues and their complexities and interactions. This example involves two regions, A and B, separated by 200 miles. Region A contains 31 GW of generating capacity and no load. Region B contains 32 GW of generating capacity and 50 GW of load. Both regions contain a wide range of generating capacity, with running costs (or bids) that vary from zero to almost $160/MWh. The load in Region B ranges from 20 to 50 GW, with a load factor of 63%.

We calculated the cost of congestion as the difference between (1) the cost of generation (including generators in both regions) to serve the load in Region B when transmission capacity between the two regions is limited, and (2) the cost of generation when transmission capacity between the two regions is infinite. The generation costs in both cases are calculated for every hour of the year.

Figure 7 shows the cost of congestion as a function of the transmission capacity connecting the two regions. With 21 GW of transmission capacity (the baseline in this example), electricity consumers in Region B pay $87 million a year because of congestion. As the amount of transmission capacity increases, the cost of congestion declines because the number of hours that congestion occurs and the price differences between A and B decline. However, as shown in Figure 7, this decline is highly nonlinear, with each increment of transmission capacity providing less and less economic benefit. Expanding transmission capacity from 20 to 21 GW lowers the cost of congestion $99 million/year, expanding capacity from 21 to 22 GW saves $44 million, and expanding capacity from 22 to 23 GW cuts costs by only $29 million.

Figure 7 The annual cost of congestion as a function of transmission capability between hypothetical regions A and B.



The relationship between the benefits of adding transmission capacity between A and B to reduce congestion costs and the costs of doing so are highly nonlinear because of (1) nonlinearities in congestion costs, (2) economies of scale in transmission investments, and (3) the lumpiness of transmission investments. For this example, if the goal is to increase capacity by 0.5 GW, it makes sense to build either two 230-kV lines or one 345-KV line, but not a 500-kV line. On the other hand, it is most cost effective to use 500-kV lines when expanding capacity by 1 GW or more. Indeed, the benefit/cost ratio for 230-kV lines increases in going from an addition of 0.5 to 1.0 GW, but then declines as more capacity is added. On the other hand, the benefit/cost ratio is more than 2 for the addition of a 500-kV line to expand capacity by 1.5 or 2.0 GW.

What happens to these costs and benefits if additional generating capacity is built in Region B, close to the load center? Adding 0.5 GW of capacity with a running cost of $30/MWh reduces congestion costs by

$19 million/year. Adding 2 GW of such capacity reduces congestion costs by $59 million/year. If the new generating capacity added to Region B had a running cost of $57/MWh, its congestion-reduction benefits would be only $14 and $35 million/year for 0.5- and 2-GW additions, respectively. These benefits are about two-thirds of those that would occur with new capacity at $30/MWh. Clearly, building new generation in Region B would undermine the economics of adding transmission capacity between regions A and B.

The congestion-reduction benefits of each additional MW of generating capacity are less than the benefits of earlier additions. This effect is especially pronounced as the bid prices of the new units increase. For the more expensive of the two units there is no benefit from adding more than 1.5 GW of generating capacity in Region B because other generators are less expensive. Once again, the results are highly nonlinear.

If loads grow at 2% a year, the annual cost of congestion (assuming no additions to either generating or transmission capacity) increases from $87 million in the initial year to $125, $162, and $250 million in the second, third, and fourth years. Such increases in load make transmission investments substantially more cost-effective. If loads respond to prices, such that loads are higher at low prices and lower at high prices, congestion costs would be reduced. In this example, as the price elasticity of demand increases from 0 to 0.02, 0.04, and 0.08, congestion costs are reduced from $87 million to $48, $25, and $7 million a year. For the ranges in load growth and price elasticity considered here, congestion costs vary from $7 to $250 million a year when the amount of transmission capacity between the two regions is 21 GW. Making decisions on how much money to invest in equipment with lifetimes of several decades is difficult in the face of such uncertainties about future load growth; customer response to dynamic pricing; and the amounts, locations, and running costs of new generating units.

The discussion so far has focused on the benefits of reducing congestion. But not all market participants benefit when additional transmission is built to relieve congestion. In particular, loads on the low-cost side of the constraint and generators on the high-cost side of the constraint lose money when congestion is reduced. For example, a generator in Region B with a bid price of $42/MWh would earn $6.9/kW-year when the transmission capacity between regions A and B is 20 GW. Expanding transmission capacity to 21 or 22 GW would reduce that generator's earnings to $4.6 and $3.7/kW-year, reductions of 33% and 46%, respectively. Such large prospective losses would likely engender substantial opposition to efforts to reduce congestion. (If Region A had loads that enjoyed the benefits of Region A's low-cost generation, those loads would also oppose efforts to reduce congestion.)

Finally, investors considering additional generation in Region B may worry that future construction of a new transmission line between A and B would undercut the value of their new generation.

Generation and Load Alternatives

The Department of Energy Task Force on Electric System Reliability (1998) recommended that RTOs "ensure that customers have access to alternatives to transmission investment including distributed generation and demand-side management to address reliability concerns and that the marketplace and the [RTO's] standards and processes enable rational choices between these alternatives."

Transmission planners can encourage nontransmission alternatives in two ways. The simplest method is to provide transmission customers with information on current and likely future congestion costs. Such information—coupled with locational pricing for congestion and losses—on the costs and benefits of locating loads and generation in different places could motivate developers of new generation to pick locations where energy costs are high, thereby reducing congestion costs. Similarly, such information could motivate load-serving entities to offer load-reduction programs to their customers in those areas where energy prices are high because of congestion. For example, the National Grid USA (2000) transmission plan included a map of New England (Figure 4) showing areas where new generation would worsen congestion and areas where new generation would reduce congestion. An alternative approach to the provision of information only is to pay for nontransmission alternatives. With this approach, the RTO would first prepare a transmission plan. This plan would likely include one or more major transmission projects (new lines and/or substations). Next, the RTO would issue a request for proposals for alternatives and then review the proposals to see if they were less expensive than the original transmission project and provided the same or better reliability and commercial benefits that the transmission project would. Ultimately, the least-cost solution to the identified transmission problem would be acquired by the RTO and recovered through transmission rates.

Appropriately comparing transmission to load or generation, however, is difficult because they differ in construction leadtimes, project lifetimes, availability, capital and operating costs, market type, and technical applicability:

- Lifetimes—Transmission investments are long-lived (30 to 50 years). Generators typically have shorter lifetimes, and load-management projects may have much shorter lifetimes (e.g., if a building is extensively remodeled, the load-management systems may be removed and replaced with alternative systems for lighting, heating, cooling, and ventilation). The longer lifetimes of transmission projects enhance confidence in their ability to provide the needed service for many years; however they reduce flexibility to respond to changed circumstances in the future.

- Availability—Transmission equipment typically has very high availability factors, much higher than those for either generation or load.

- Capital and operating costs—Although the capital costs of transmission can be high, operating costs are very low. The operating costs for generators are high and depend strongly on uncertain future fuel prices. The tradeoff here is between high sunk costs (once the transmission project is completed) against uncertain operating costs for generation and load management.

- Type of market—The returns on transmission investments are regulated, today primarily at the state level and in the future primarily by FERC. The profitability of generation investments, on the other hand, is determined largely by competitive markets. Comparing costs (e.g., economic lifetimes and rates of return) between regulated and competitive markets is difficult.

- Technical applicability—Nonwires resources cannot always solve the problems at which the transmission investment is aimed (e.g., transient stability or the need to replace aging or obsolete transmission equipment). Also, connection of the resource to the grid may impose new costs on the system (e.g., if system-protection schemes must be upgraded).

The difference in lifetimes between the transmission project and its alternatives raises the issue of whether the alternatives should be assessed against the cost of deferring the transmission project for several years or against the full cost of displacing (eliminating the need for) the transmission project. If the transmission project will likely be needed in any case, although at a later date, the deferral approach makes sense.

Although the concept of encouraging competition between transmission investments and generation and load alternatives is appealing, implementation can be difficult. The Tri-Valley project, proposed by Pacific Gas & Electric in northern California, illustrates these difficulties. The project involves the construction of new 230-kV transmission lines, construction of new 230/21-kV substations, and upgrading of a substation to 230-kV service. The California ISO issued a request for "cost effective and reliable alternatives… from generation and/or load alternatives to the proposed PG&E transmission project" (Winter and Fluckiger, 2000). Alternatives were required to be available between the hours of 8 am and 1 am for up to 500 hours between April 1 and October 31 each year from 2001 through 2005. The ISO sought call options on about 175 MW. The request was issued in January 2000 with responses due in late March. The ISO received four proposals, all of which it subsequently rejected.

The ISO rejected all four bids because they failed one or more of the evaluation criteria, which involved satisfaction of the ISO's reliability criteria, commencement date, operating characteristics, ability to provide the proposed services, cost, safety, impacts on markets (in particular, effects on generator market power), and environmental implications. The key reason the bids were rejected is they were substantially more expensive than the transmission project. Also, the transmission project was expected to provide more capacity to the system than the generation and load-management projects.

A year later, when faced with a similar situation, the ISO decided against issuing a competitive solicitation. In this case, the ISO approved construction of the San Diego Gas & Electric Valley-Rainbow transmission project (Detmers, Perez, and Greenleaf 2001). In part because of the electricity crisis California faced, the ISO decided that this project should be considered part of a "broad strategy by the state of California to put into place a robust transmission system to support reliable service to consumers." The benefits of this 500-kV transmission project would not be realized by generation or load-management alternatives. The proposed transmission line would permit generation from other parts of California, Arizona, and New Mexico to be moved to the San Diego area. The project would also permit new generators being located near San Diego to reach distant markets. Finally, the project would provide local reliability benefits that otherwise would have to be purchased through reliability-must-run contracts. These reliability benefits would occur because the transmission project "integrates San Diego with the rest of the Western Interconnection, providing significant access to a wide variety of resources rather than being limited to the local area resources and the common concerns that they share, such as adequacy of gas supply."

The limited analysis conducted to date seems to argue against widespread use of suitably located generation and load management as alternatives to some new transmission projects. However, these analyses were conducted primarily by transmission engineers who are more comfortable with transmission and understand transmission better than they do its alternatives. Also, the continued opposition to construction of new transmission facilities requires the electricity industry to look long and hard at possibly viable alternatives.

New Technologies

Superconductivity, power electronics, information systems, and other new technologies could revolutionize transmission and make it easier to expand the system through merchant, rather than regulated, projects. According to Howe (2001), "Recent advances in materials science offer the prospect of another industry paradigm: one based on robust facilities-based competition in network services, without the environmental and land-use impacts of traditional 'big iron' solutions." Some of these advances include:

- Superconducting Magnetic Energy Storage—High-speed magnetic-energy-storage devices that are strategically located in a transmission grid to damp out disturbances. These systems include a cryogenically cooled storage magnet, advanced line-monitoring equipment to detect voltage deviations, and inverters that can rapidly (within a second) inject the appropriate combination of real and reactive power to counteract voltage problems. By correcting for potential stability problems, these systems permit the operation of transmission lines at capacities much closer to their thermal limits than would otherwise be possible.

- High-Temperature Superconducting cable—Can carry five times as much power as copper wires with the same dimensions. Although initially applicable to underground distribution systems in dense urban areas, eventually this technology may be used for medium- and high-voltage underground transmission lines. The use of these cables would greatly reduce the land required for transmission lines in urban areas and lessen aesthetic impacts and public opposition.

- Flexible AC Transmission System (FACTS) devices—A variety of power-electronic devices used to improve control and stability of the transmission grid. These systems respond quickly and precisely. They can control the flow of real and reactive power directly or they can inject or absorb real and reactive power into the grid. These characteristics provide both steady-state and dynamic benefits. Direct power-flow control makes the devices useful for eliminating loop flows. The very fast response makes the devices useful for improving system stability. Both characteristics permit the system to be operated closer to its thermal limits. FACTS devices include static var compensators, which provide a dynamic source of reactive power; thyristor-controlled series capacitors, which provide variable transmission-line compensation (effectively "shortening" the line length and reducing stability problems); synchronous static compensators, which provide a dynamic source of reactive power; and universal power-flow controllers, which control both real- and reactive-power flows.

- High-Voltage DC (HVDC) systems—HVDC lines have several advantages over AC transmission lines, including no limits on line length, which is useful for moving large amounts of power over long distances; reduced right-of-way because of their more compact design; precise control of power flows, eliminating loop flows; and fast control of real- and reactive-power to enhance system stability. The primary drawback of HVDC is the high cost of the converter stations (which convert power from AC to DC or vice versa) at each end of the line.

- HVDC Light—This new approach to HVDC uses integrated-gate bipolar transistor-based valves (instead of thyristor-based valves) in the converter stations. These new valves permit economical construction of lower-voltage lines, which greatly increases the range of applicability for DC lines; involves much more factory construction instead of onsite construction, which lowers capital costs; and provides better control of voltages and power flows. HVDC-light lines have recently been built in Australia and Denmark, and others have been proposed for the United States.

- Real-time ratings of transmission lines—Represent another use of advanced information technologies to expand the capability of existing systems (Seppa, 1999). Such systems measure the tension in transmission lines, ambient temperature and wind speed, or cable sag in real time; the results of these measurements are telemetered to the control center, which then adjusts the line rating according to actual temperatures and wind speeds.

In spite of their wonderful attributes and recent declines in their costs, these technologies are generally too expensive to warrant their widespread use today. (To date, they have been deployed in a few locations, primarily by utilities to improve the performance of their systems.) However, as the technologies are improved and demonstrated, their costs will likely continue to drop enough that they become cost effective. When that day arrives, transmission planning will be simpler, primarily because market participants (rather than regulators or system operators) will be able to decide whether to invest in these systems and will be able to retain their benefits (because some of these technologies use devices that permit direct control of power flows).

Merchant Transmission

The kinds of new technologies discussed above make it possible for unregulated, for-profit entities to build what are called merchant transmission projects. Under such circumstances, the need for centralized transmission planning is greatly reduced. Three such merchant projects have been proposed in the United States:

- TransEnergie US proposes to build a 330-MW, 26-mile submarine cable under Long Island Sound to connect Connecticut and Long Island. FERC approved the project in June 2000, after which TransEnergie held an open-season subscription for the DC line's capacity.

- The Neptune Regional Transmission System, announced in May 2001, is a set of DC projects to link the northeastern U.S. with eastern Canada. All four phases involve submarine cables. The total project calls for 3600 MW of transfer capability from Canada to the U.S. FERC approved the project in July 2001.

- The TransAmerica Grid, proposed by Black & Veatch and Siemens AG, calls for construction of large mine-mouth coal plants in Wyoming and DC lines to connect this new generation with Chicago and Los Angeles. These transmission lines, about 1000 miles each, would cost $4.5 billion and would greatly expand the transfer capability between the eastern and western interconnections.

All three of these projects are DC. As noted by Liles (2001):

"…the benefit of DC lies in the ability of the project's operator to control the flow of power on the line. What you put in is what you get out, net of resistive losses. Loop flow is not an issue. Contrast that with the existing AC network, in which power flows freely throughout the system according to the impedances of the lines…. Physically firm transmission capacity can be bought and sold on a DC line. For DC lines, the contract path is the actual path over which the power flows."

Such merchant projects are feasible only if the owner can obtain clear property rights to the transmission investment. According to Rotger and Felder (2001), such property rights require the use of "bid-based, security-constrained locational pricing for transmission services" as well as financial transmission rights. The PJM and New York ISOs have such systems in place.

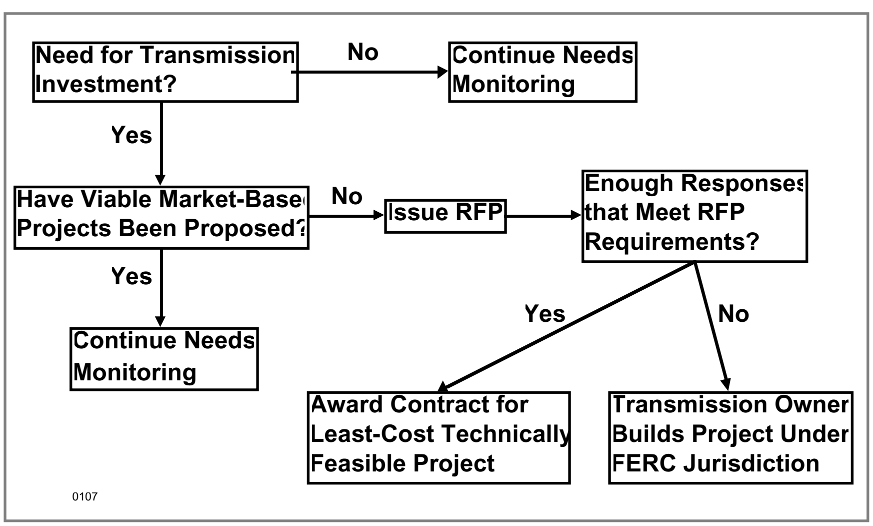
Rotger and Felder (2001) propose a regulatory backstop in case competitive markets do not construct enough transmission to maintain reliability. Their vision of a backstop, however, is quite limited. It calls for the RTO to assess the need for new transmission to meet reliability requirements only, with no consideration of economic projects that might reduce costs to market participants. The RTO, having identified transmission projects needed for reliability, would then issue a request for proposals for such projects (Figure 8).

Although attractive in concept, no merchant transmission projects have yet been built in the United States. It is also unclear whether such projects are viable only where direct control is possible (e.g., with DC lines and other new technologies such as FACTS systems) or whether such projects are feasible for AC systems. If merchant projects are limited to those where control is possible, it is unclear whether such projects will play a major role in expanding North American transmission systems or will play more of a niche role.

Projections of New Generation and Load Growth

The deintegration of the traditional utility, which encompassed generation, transmission, distribution, and customer service in one entity, raises two important informational issues for transmission planning. First, from what sources will transmission planners obtain reliable information on the locations, types, capacities, and in-service dates of new generation? Second, what entity will be responsible for developing projections of future load growth?

Figure 8. Proposed RTO backstop process to be used when competitive markets do not produce enough transmission expansion to meet reliability requirements.



Historically, utilities reported their plans for new generation to the Energy Information

Administration (EIA) and NERC. Increasingly, however, new generation is being constructed by independent power pro-ducers. Although EIA collects data from such entities, long lags can occur between the time a company announces a new power plant and the time it shows up in the EIA system. The Electric Power Supply Association also collects data on power-plant construction plans. Because the Association does not provide details on the status of the project, it is hard to determine the probability that a project will get built and produce power. The probability of unit completion increases as the project moves from initial announcement to applications for siting and on to environmental permits, construction, and completion.

Analogous issues concern projections of future load growth. System operators (ISOs and, in the future, RTOs) monitor and record data on power flows down to the level of distribution substations. But, because of their focus on bulk-power flows and wholesale electricity markets, system operators are unlikely to have data on end-use demand by customer class. The competitive load-serving entities may have such information but are unlikely to want to make such information publicly available. The electricity industry needs to develop a system to collect relevant data on customer electricity-using equipment, load shapes, and load levels and to provide this information to transmission planners (as well as to other entities responsible for maintaining a healthy bulk-power system).

Recommendations

As the electricity industry continues its long and complicated transition to a fully competitive state, the requirements for transmission planning are changing and expanding. This paper outlined a proposed planning process that RTOs might adopt in a restructured electricity industry. However, most of the details for this process are not yet developed. Similarly, FERC's requirement in Order 2000 that "the RTO must have ultimate responsibility for both transmission planning and expansion within its region" is largely undefined. These gaps lead to several recommendations for the U.S. Department of Energy (DOE), FERC, and RTOs to consider:

- Provide technical assistance to ISOs, RTOs, regional reliability councils, federal power agencies, and other organizations to develop and demonstrate improved transmission-planning methods. Such methods would feature active public involvement throughout the planning process, comprehensive consideration of nonwires solutions to transmission problems, analysis of the benefits and costs of different solutions under a wide range of possible futures, and a focus on practical solutions that can be readily implemented. DOE could work with the planning staffs at various electricity-industry organizations to develop improved planning processes, analytical tools, and plans. DOE could then widely disseminate the results of these case studies (i.e., through publications, conferences, and workshops) so that others in the electricity industry can learn from these experiences.

- Assist FERC in the development of planning standards that FERC would then use in its review and approval of RTO transmission plans. This activity would add detail to the FERC Order 2000 requirement that RTOs be responsible for planning (Function 7). Based on the case studies described above, DOE could work with FERC staff to define what public involvement is required, what data RTOs must make available to market participants on the current and likely future states of the transmission system, what FERC means by "least cost" in its requirement that RTOs be responsible for transmission planning and expansion, and the extent to which planning should be proactive (i.e., guide future investments in new generation and demand-management programs), rather than only react to generator-interconnection requests and load growth. These standards should focus on performance (what is to be accomplished) and not be prescriptive, to permit flexibility within and among RTOs.

- The RTOs, acting under FERC requirements, could ensure that transmission planning and expansion fully comply with NERC and regional planning standards. Such compliance would ensure that transmission systems are adequate and meet reliability and commercial needs.

- The RTOs should identify the transmission-information needs of market participants (including generation developers, load-serving entities, transmission owners, and others) to guide their investment and operating decisions so they are consistent with current and likely future transmission conditions and costs. The information needs of interested stakeholders will vary considerably. Some participants will only want maps showing "good" and "bad" locations for new generation from the perspective of the transmission system, while other participants will want detailed load-flow studies that show voltages and flows throughout the system, under various on- and off-peak conditions. Periodically, such information should be made available to market participants.

- Study the potential role of merchant transmission. DOE, again working with RTOs and other market participants, could conduct a study to determine the extent to which merchant (nonregulated) transmission projects can meet future transmission needs. Among other topics, this study should examine the possibility of extending merchant transmission to AC projects, rather than the DC projects that are the focus of today's merchant transmission facilities. Another critical issue concerns the meaning of the RTO role as a "backstop" to market solutions. Under what conditions should the RTO build (or pay for) a project that is needed to solve transmission problems that market participants have not, acting on their own, chosen to solve? This study should also address the danger that merchant transmission will "cherry pick" the most profitable transmission projects, leaving the regulated entity (more accurately, transmission customers in general) to pay for the less cost-effective transmission projects that, nevertheless are required for reliability or to connect customers to the system.

Conclusions

Maintaining a healthy transmission system is vital for both reliability and commerce. Because electricity is essential to our modern society, public policy should ensure suitable expansion of the nation's transmission grids. Unfortunately, the historical record shows a clear and long-term decline in U.S. transmission adequacy

(Hirst and Kirby 2001). Specifically, the amounts of new transmission added during the past two decades have consistently lagged growth in peak demand. To make matters worse, projections for the next five and ten years show continued declines in adequacy, although some of the projected need for new transmission may be met by the construction of generating units close to load centers.

To further compound the problem, transmission planning is not keeping pace with the need for such planning. Because transmission owners and ISOs are receiving so many requests for generator interconnections, they are unable to devote the staff resources needed to develop proactive transmission plans. That is, they are focused primarily on preparing the system-impact and facility studies required for these new interconnections. Thus, some transmission plans are little more than compilations of individual generator-interconnection studies.

Because transmission planners have insufficient time and resources, little information is being provided proactively to energy markets on the costs and locations of congestion. Such information could help potential investors in new generation decide where to locate new units. Such information could also help load-serving entities decide what kinds of dynamic pricing and load-reduction programs to offer customers in different locations. More broadly, such information could reduce the need for centralized planning and construction of new transmission facilities.

Because generation and load can serve, in some instances, as viable alternatives to new transmission, transmission plans need to explicitly consider such nontransmission alternatives. Whether the transmission system (i.e., transmission users in general) should pay for these generation and load projects is unclear and hotly contested. At a minimum, transmission planners should provide information (again based on analysis of past and likely future congestion costs) on suitable locations for new generation and load management. In a similar fashion, alternative methods for pricing transmission services (including charges for access, congestion, and losses) would affect transmission uses. These changes in transmission flows would, in turn, affect the need for new facilities. Thus, transmission planning should include assessments of alternative pricing methods to improve efficiency in transmission utilization.

Transmission planning may be too narrowly focused on NERC and regional reliability-planning standards. That is, transmission planning may pay insufficient attention to the benefits new transmission investments might offer competitive energy markets, in particular, broader geographic scope of these markets (which would encourage greater diversity in the fuels used to generate electricity) and a reduction in the opportunities for individual generators to exercise market power. Although some plans consider congestion (either congestion costs or curtailments and denial of service), such considerations are more implicit than explicit. As shown here, congestion costs (both in real time and in forward markets) can provide valuable information on where and what to build.

Advanced technologies offer the hope of better information on and control of transmission flows and voltages. Such improved information and control would permit the system to be operated closer to its thermal limits, thereby expanding transmission capability without increasing its footprint. Thus, new technologies may reduce fights about transmission siting. In addition, these technologies, because they permit control of power flows over individual elements (e.g., DC lines), may make it attractive for private investors to build individual facilities (merchant transmission). Unfortunately, these advanced technologies are still too expensive for widespread application, although some are economic in niche applications.

The separation of generation from transmission and of retail service from transmission poses difficult information problems for transmission planning. Specifically, transmission planners need detailed information on the timing, magnitudes, and locations of new generating units; the developers of these facilities are unwilling to share competitive information until required to do so (e.g., for environmental permits and for transmission-interconnection studies). Planners also need detailed information on the locations and magnitudes of future loads. In a retail-competition world, it is not clear what entities will have the information necessary to produce reliable projections of retail load and whether those entities will be willing to share these projections with transmission planners.

Finally, the economies of scale in transmission investment argue for overbuilding, rather than underbuilding, transmission. It is substantially cheaper per GW-mile to construct a higher-voltage line than a lower-voltage line. The higher-voltage line also requires less land per GW-mile, which should reduce opposition from local landowners and residents. Also, building a larger line now eliminates the need to build another line in several years. This situation can eliminate the need for another potentially bruising and expensive fight over the need for and location of another transmission line. Also, the availability of suitable land on which to build transmission lines can only go down in the future, as population grows and the economy expands. On the other hand, overbuilding can increase financial risks for the transmission owners.

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Transmission Siting and Permitting

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Introduction

In order to construct new transmission facilities or to significantly upgrade existing facilities in the U.S. electricity system, developers typically need approval from several state and federal agencies. This process has, in recent years, become protracted and difficult. The difficulty is hardly surprising given that transmission facilities are highly visible structures that may span long distances and must somehow fit into physical surroundings that are already in use for other purposes. Incorporating these facilities into the landscape and taking fair account of the wide range of legitimate interests affected by them is challenging.

Nevertheless, many observers and participants in the electricity sector now regard transmission siting and permitting procedures as a major reason why the development of new transmission facilities is not keeping up with the need. Critics say that the siting and permitting process has become unnecessarily cumbersome, delay prone, and subject to breakdown. Some observers argue that current state-based regime for managing siting and permitting is not well adapted to the review of proposed large-scale multistate transmission projects that are or may soon be needed to serve regional bulk power markets, perhaps with little benefit to local electricity consumers. Other officials familiar with state processes agree that regulatory processes can and should be improved, while noting that there is also potential to improve the siting and planning practices of transmission owners or other applicants for proposed new facilities.

Given the vital importance of the transmission network, it is essential to the national interest that transmission siting and permitting procedures work for society in practical terms. That is, these procedures must lead to timely decisions by appropriate agencies about whether proposed facilities would serve the public interest, and to timely approval of routes or sites for facilities that are deemed necessary. This paper examines current siting and permitting practices and ways to improve them. Specifically, the paper:

- Examines existing government and industry practices related to siting and permitting,

- Identifies key or frequent problems with these practices,
- Identifies policy options that should be considered to resolve these problems, and
- Discusses objectively some of the advantages and disadvantages of the options, so they can be considered by federal and state policy makers, corporate officials, and the public.

The policy options discussed fall into three categories:

- Creating new regional institutions to facilitate transmission siting and permitting, either for all new transmission facilities or for large or critically important facilities;
- Improving the current state-based governance regime;
- Making siting-related practices by industry and government agencies more effective, regardless of governance structure.

The remainder of this paper is divided into six sections:

- An assessment of the existing state-based siting regime.
- A discussion of transmission siting from a regional perspective, the reasoning that has led to increased interest in establishing regional institutions for siting new transmission facilities, and the options for designing these institutions.
- Issues related to defining "regional transmission facilities." Some such definition would be useful for determining which new facilities would be subject to the jurisdiction of regional siting institutions.
- Options for improving the existing state-based siting regime.
- Options that could be pursued under any governance structure to improve siting-related practices by government agencies and industry.
- Summary and conclusions.

Assessment of Current Siting Regime

The North American electricity grid is a monumental feat of imagination, planning, and engineering. The grid links generators to cities; cities are linked together and with rural areas; and many electricity suppliers are made accessible to users. Networking delivers a very high standard of reliability at reasonable cost, and the U.S. economy depends heavily upon this high level of reliability. Some government authority approved construction of most of the power lines that make up the grid.

Siting transmission lines is understandably difficult, involving complex engineering, social, and land use considerations. As aggregate electricity usage in an area grows, reliability tends to degrade unless the transmission network is strengthened. There are often many ways to meet a need for grid enhancement, and choosing a good solution is likely to involve tradeoffs among many factors, including cost. Arriving at good solutions often requires long lead times and the development and implementation of a flexible long-term plan for optimizing the transmission grid and related facilities.

Utilities, whether publicly or privately owned, involve a mixture of public and private interests. One of their roles is to bring forward proposals to meet transmission grid needs and implement these proposals if they are approved by government agencies. Consumers rely on government agencies to select the transmission proposals that are most likely to have value well in excess of their cost over the working life of the investment. Because the future is uncertain and reliance on forecasts is unavoidable, the selection process will not always result in the best decisions. However, the goal is that the system used for siting electric transmission lines will produce timely, high-quality decisions in most cases.

Siting electric transmission lines is currently a state responsibility.[1] Each state may address transmission siting in its laws, and most have done so. In a few states, utilities are required only to give notice of intent to build a transmission line; after a specified period, if no challenges are raised, the utility may proceed with acquisition of right of way (if needed) and construction. In most states, however, the utility must demonstrate to a siting authority that the proposed facility is needed, and the siting authority must confirm that construction of the facility will serve the public interest.

Most power lines are proposed in states that have formal siting authorities. Some transmission proposals are withdrawn after supporting evidence is assessed during the siting process. A few proposals make it all the way to a decision by the siting authority and are then rejected. Rejections represent failures of analysis and communication somewhere in the planning and siting processes, and they are costly to all parties, including the public. The objective of the subsections below is to examine the existing siting process and analyze some of its successes and failures.

Description of the Transmission Siting Process

A utility typically files a siting proposal when it feels that there is justifiable need for additional transmission capacity and that the proposed solution is robust. In most states, the proposal goes to a siting authority, most often the regulatory utility commission. A significant number of states have a separate siting authority that may include officials from other affected state agencies.

Usually, the process is a "contested case," which means that the decision will be based on evidence presented by the applicant and other parties. Parties ("intervenors") may intervene in the case either by right (e.g., the state public advocate) or by permission if they demonstrate to the siting authority that a distinct interest is at stake that is not otherwise sufficiently represented. The utility decides when the process starts and controls most of the relevant information. Sometimes, intervenors fill gaps in the information provided by the utility.

In some states, a specific amount of time is allotted for reviewing a transmission siting proposal. The time limit may be reached or even exceeded in complex cases or cases that involve much procedural maneuvering; this may trigger a rejection of the proposal by the siting authority on procedural grounds. Other states have no spe-

[1]With the exception of the federal power marketing administrations and the Tennessee Valley Authority, which have their own siting authorities.

cific time limit. Still other states, in order to reduce utility incentives to hold back details about a proposal, allow a time limit to be activated only after a finding by the siting authority that the application is complete.

In some states, the process focuses on the proposal under consideration rather than on how best to address a grid need. In these cases, a rejection may not be accompanied by guidance about how to address better the need that the original proposal was intended to meet. The prospective lack of such guidance and the desire to avoid rejection may motivate some parties to work during the case to improve the project after filing, based on evidence and arguments during discovery and hearings.[2]

Electricity consumers pay for transmission facilities through their electricity bills.[3] Consumers depend on regulators to allow the incorporation into electricity rates only the costs related to transmission facilities required to serve their area's long-term needs. Transmission costs represent approximately 10% of the nation's total electric bill.[4]

An environmental assessment is often required for a transmission proposal. Environmental issues of interest include:

- Concern about opening new areas to development—for example, roads may be needed for access to maintain lines, and development may follow roads;
- Potential disruption of habitat by reducing the size of continuous undeveloped spaces;
- Potential impacts on endangered species; and
- Visible impacts that may create aesthetic concerns, especially in scenic areas.

In most states, the utility must apply for and obtain a "certificate of public need" (the name of this document varies from state to state) for a transmission facility. This certificate is extremely important; it indicates that the designated government authorities have reviewed the proposed project, evaluated the tradeoffs involved, and concluded that, overall, the project is in the public interest even though some legitimate private or public interests may be adversely affected.

The formal criteria for determining "need"[5] vary. Some commonly used criteria are

- Someone is willing to invest in the project (in other words, the project is perceived to have significant marketable value).
- The project is needed to maintain the reliability of the bulk power supply system.[6]

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[2]An iterative process has its merits but exposes intervenors to the risk of having to evaluate an essentially new proposal in the midst of the process. The siting authority must "manage the clock" to ensure that everyone is treated fairly.
[3]Merchant transmission costs find their way into retail prices though by a different path than regulated transmission rates.
[4]DOE. 2002. *National Trasmission Grid Study.* U.S. Department of Energy.
[5]There is no practice or mechanism for determining regional or interstate need. The Electric Reliability Council of Texas (ERCOT) performs this function in a way that some expect will become typical for Regional Transmission Organizations (RTOs)—providing unbiased and competent information to clarify and focus the work of individual utilities on addressing validated needs.

- The project is needed for regional electricity commerce.[7]
- The project is needed to interconnect an approved generator to the grid.[8]

In many states, decision makers must consider alternatives to the primary proposal. Some states have specific instructions concerning alternatives that the utility must present. Siting authorities are typically interested in route and non-transmission alternatives when these are relevant.[9]

Substitutability of Transmission and Nontransmission Resources

There are many substitutable ways to meet customer needs for delivery of energy. Here are two examples:

1. Consider a community that has experienced significant customer demand growth and has been relying on generation located outside the area but delivered to customers by wires that are beginning to reach capacity limits. In this case, the capacity of the lines could be increased, or generation could be added within the community to reduce the need for imports. Alternatively, customers could reduce their demand on the grid, either by using energy more efficiently or by making their own electricity. Deploying several approaches may avoid overreliance on any one. Examples of these alternative approaches are being deployed now in New York City for the explicit purpose of improving electricity system reliability.

2. Consider a market in which a transmission constraint leads to energy clearing prices that differ by two cents between the two sides of the bottleneck in many hours. Possible solutions include adding transfer capacity to allow the low-cost resources on one side of the constraint to flow freely to the other side. Or it might be possible to add lower-cost resources in the region where energy prices are higher. A third alternative would be to reduce demand in the region where power is more expensive if a reduction would mean avoiding use of the most expensive generation resources. An example of adding resources in the region where power is more expensive appears to be unfolding in Pennsylvania where differences between eastern and western prices are moderating because natural-gas-fired generation has been added in the east.

In both examples, structural improvements, such as more functional markets and better pricing regimes, are contributing to the resolution of problems that might once have been solved by transmission facilities alone. These alternatives should be considered during an investment planning cycle prior to and again during permitting so that the public can see and appreciate the decision-making process.

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[6]Demonstrating this particular need requires competence in either deterministic or probabilistic transmission planning models as explained briefly in Section 6. Using just one approach leaves the applicant vulnerable to challenge.
[7]For some states, serving regional commerce is a vital purpose of the grid. For others, it is secondary to maintaining reliability.
[8]One commenter at the public workshops organized for the National Transmission Grid Study (NTGS) by the U.S. Department of Energy suggested that inadequate attention is being given to transmission needs associated with bringing some new generation on line. If this is true, a need buildup may be accumulating that could result in belated justification for new power lines in some areas.
[9]Texas requires submittal of alternative route options as well as analysis of the usefulness of demand-side management and distributed generation in lieu of new lines.

The cost to prepare a transmission proposal and support it through the siting process is significant and can vary depending on the complexity of the project and degree of public concern.[10] Regulated companies expect that federal and state supervised rates will recover the cost of the project plus a reasonable return. Merchant transmission companies rely on a business plan that forecasts sufficient revenues from the sale of transmission services to cover their costs and provide an acceptable return on invested capital. Their charges are also eventually reflected in retail electric prices.

A crucial and volatile factor in the transmission siting process is the public trust. It is extremely important that the managers of the process and other major parties act in specific cases so as to gain and keep the public's confidence that the siting process will generally lead to sound outcomes that serve the many public interests at issue.

Due Process in Transmission Siting

Due process is an important element in the American judicial system, including the transmission siting process. By means of due process rules, the regulatory agency that manages the process balances the interests of many parties, including potential intervenors who need a sufficient opportunity to review and critique the particulars of a proposed transmission project, the utility that is charged with providing reliable service at just and reasonable rates, and consumers.

The first element of due process is notice. Parties who may be affected by a project have a legal right to hear about it sufficiently in advance to make a reasoned response if they choose. When a project affects many communities, notice must be provided so that all communities are informed.[11]

A complete filing is also a necessary element of due process. Potential intervenors need full information about the project, presented in non-technical terms. Information provided by utilities may be incomplete. Regardless of the history or regulatory time limits on the case, filing of incomplete applications or withholding of relevant information puts the proposed project at risk, and may create mistrust, conflict, delay, and/or result in outright rejection of the proposal.

Another key element of due process is the determination of which parties are allowed to participate. The state is usually represented, and any relevant point of view not adequately represented by others is generally allowed. Those designated as "parties" to the case receive all information submitted to the siting authority by any other party and have the opportunity to ask and be asked discovery questions and to put on and cross-examine witnesses. Typically, parties pay their own costs. Low-budget participation is possible, but expert advice is expensive, which limits the participation of some intervenors.[12]

[10]In September 1995, the Florida Public Service Commission (PSC) voted to allow Florida Power to recover $23 million in costs spent on a proposed 500-kV line that was never built. The line was approved by the PSC in 1984 for reliability. However, continued local opposition led to protracted and costly litigation. Florida Power eventually developed an alternative plan involving more intensive monitoring of the status of key transmission lines in the area, interruption of service to a limited number of customers in emergency situations if necessary, and reactivation of a 115-kV line that had earlier been retired from service. (*Electric Utility Week,* 1995.)

[11]This concern is spoofed in *The Hitchhiker's Guide to the Galaxy,* by Douglas Adams, in which notice to demolish the Earth was posted at Alpha Centauri.

[12]Some of the most tenacious non-government intervenors have wealthy benefactors or pro bono advocates. In rare cases, states provide funding, usually assessed from the applicant, for intervenors.

“Discovery” is the process of insuring that all relevant facts are available to all parties before hearings. Because utilities possess most of the information relevant to transmission proposals, they usually have a greater discovery burden—that is, they must distribute to others all relevant information. In some cases, however, other parties present competing alternatives and thus become subject to major discovery burdens.

Conflicts may result if some information essential to understanding the need for or the design of a project is declared to be confidential to protect allegedly proprietary details. A simple solution is an agreement that allows all parties to see the information but requires that they use it only for the purpose of the case. Even with such an agreement, disputes may persist since the information may be important to enable the public to understand the need for the project, and there is no practical way to include the public in a protective agreement. In addition, there may be lingering disagreement on how proprietary the information is in the first place. In many jurisdictions, applicants face no formal penalty if they withhold information as a strategy to divert attention or delay review of the proposal; however, an applicant who withholds information risks losing the trust and goodwill of regulators and the public.

Siting authorities usually allow public comment, and many are required by law to do so. Some states require that comments be solicited in person in each affected county. For a long transmission line, many counties could be affected. Public comments are not usually used as evidence because statements are not cross-examined; however, these comments may influence the atmosphere in which the decision makers deliberate.

Technical hearings are the forum through which the siting authority collects evidence. These hearings are sometimes held before staff or hearing examiners or directly before the siting authority. Parties to these hearings can produce witnesses, and all parties can cross-examine all witnesses.

It is important that all parties understand in advance the standards for approval of a transmission proposal. These standards should be provided by the siting authority with citations of appropriate statutes, regulations, and precedents. Sometimes an issue emerges for which there is no precedent, and parties may want to know at an early stage in the case how the authority will evaluate this issue. After the siting authority issues its findings and orders, there is usually an opportunity to appeal. State courts vary in their ability to process such appeals quickly.

Key Difficulties in the Current Transmission Siting Process

Why don’t utility proposals for new transmission facilities get routinely approved within a “reasonable” time period? In fact, most smaller projects or upgrades of existing facilities are approved, often in less than a year. Notice and hearing requirements take up the bulk of the time in such cases. However, some proposals do not go smoothly, as discussed in the rest of this subsection.

Significant difficulties arise when a proposal is perceived by key parties to be inconsistent with important public interests. These interests may include costs as well as impacts on electric rates, the environment, property rights, protected federal land, or other sensitive land. Often, critical disagreements are about how certain tradeoffs should be evaluated and resolved. Sometimes, a conflict is the result of a party's conscious decision to be uncompromising for reasons of principle or strategy. Disputes may arise about whether certain questions have been sufficiently answered or whether parties will have access to certain information and on what terms.[13]

Major delays occur if the siting authority finds that an applicant failed to examine and present relevant alternatives, a task that entails significant effort. If more than one state is involved, the states may disagree over the proposed distribution of the societal benefits and costs associated with the line.

A bias is introduced in the weighing of alternatives if different approval venues, processes, or compensation methods are used for different options. For example, if the siting authority is not the regulatory commission, the authority may not have sufficient experience in demand-side measures to determine whether they may be superior to a power line as a means of meeting a system need. Introducing competition to the wholesale generation market has added another dimension of difficulty. Investments in generation, transmission, and demand-side measures come in regulated and competitive forms and pass through different channels for approval, so there is no single standard for comparing them, and there may be no formal opportunity for a side-by-side evaluation.

Two Instructive Transmission Siting Cases

American Electric Power's 765-kV project between West Virginia and Virginia

The painfully long, complex, controversial, and costly review of an American Electric Power (AEP) transmission project in West Virginia and Virginia is often cited as a definitive example of a dysfunctional transmission siting process. The major parties are the applicant, two states, and three federal land management agencies. After ten years of review, this project is still at least a year from final approval.

AEP first proposed the 765-kV project in 1991 to Virginia, West Virginia, the U.S. Forest Service, the National Park Service, and the U.S. Army Corps of Engineers. As initially proposed, the project's primary purpose was to maintain reliability in southern West Virginia and southwestern Virginia, and a secondary purpose was to reduce the risks of a cascading outage that could affect many states in the eastern United States. The project would have involved construction of a new line about 113 miles long from an AEP substation in Wyoming County, West Virginia, to an AEP substation near Cloverdale, Virginia. Possible impacts on populated areas made the project controversial in both states, and both states held very extensive local hearings. In addition, the Forest Service issued a draft environmental impact statement in 1996 in which it recommended that the line not be constructed as proposed because it would cross sensitive areas of the Jefferson National Forest, the Appalachian Trail, and the New River.

In October 1997, AEP proposed an alternative route to the regulatory commissions in the two states. This route was about 17 miles longer than the earlier route, and the most important change was that it would go south from the Wyoming area of West Virginia before turning east, enabling the line to cross the New River

[13]There are many examples. In Illinois, a transmission project was approved only after the utility produced information requested by the commission staff; the staff had recommended that the project be denied because the information offered at the outset was inadequate. Illinois Commerce Commission Docket 92-0121 (P.R. Buxton, Personal communication).

in a less sensitive area. Several other changes were made to put the line behind ridges and to cross rivers and important natural areas at locations with lesser impacts. In June 1998, the West Virginia Public Service Commission approved its 32-mile portion of the line.

In September 1998, however, AEP agreed to a request from the staff of the Virginia Corporation Commission that the utility conduct a detailed study of an alternative route that would follow much the same path as before in West Virginia but would terminate in Virginia at an AEP substation near Jacksons Ferry. The Virginia Commission also engaged a consulting firm to prepare an independent evaluation of the route to Jacksons Ferry. After completing its review, AEP agreed that the Jacksons Ferry route was acceptable although it would not allow as much margin for future load growth as the route to Cloverdale.

In May 2001, the Virginia Corporation Commission approved the Jacksons Ferry route, chiefly because it would have fewer adverse environmental and social impacts than the route to Cloverdale. The West Virginia Public Service Commission must now review the route ending at Jacksons Ferry, even though the West Virginia portion of the route remains essentially unchanged from that which the commission approved in June 1998. In addition, the new route would cross about 11 miles of national forest in an area not studied in the Forest Service's 1996 draft environmental impact statement, so the Forest Service must do a supplementary analysis and decide whether to grant a permit for construction of the line.

The siting process for this project might have been accelerated if there had been:

- Greater coordination and cooperation among the five reviewing agencies (West Virginia, Virginia, and the three federal agencies). A significant source of delay in the earlier stages of the process was that each state commission tended to favor a route that would reduce adverse environmental and social impacts within its own state without regard for the possibility of adverse impacts in the other state.
- Presentation by AEP of a wider range of alternatives at an early stage in the process.
- Better communication between the Forest Service and the applicant. The Forest Service and the applicant could have focused earlier on the acceptability of several alternative routes across national forest lands.
- More emphasis on the “regional picture” through involvement of a regional siting institution. Because a major purpose of the line is to reduce the risk of a cascading multistate outage, this project has regional significance. The regulatory process, however, has involved only two states, and their proceedings have focused primarily on intrastate concerns.

The Cross Sound Connector

Another project, the Cross Sound Connector, illustrates the problems of focusing on a single route and also shows some additional difficulties typical of interstate projects. TransEnergie US, Ltd proposed the project in the summer of 2000. It would connect the Long Island Power Authority's Shoreham substation with a United Illuminating substation in New Haven, Connecticut, by means of a buried 26-mile undersea cable. The project has two principal purposes: to improve reliability on Long Island and in Connecticut, and to enable Long Island to import generation from New England. The project obtained required approval from

New York officials but was rejected in April 2001 by the Connecticut Siting Council, less than a year after it was proposed.

Two reasons were cited for the rejection. The primary reason was risk to valuable shellfish beds in Long Island Sound near the Connecticut end of the project. A secondary concern was that the allocation of benefits from the project between New York and Connecticut was not equitable in comparison to the burdens involved. In August 2001, TransEnergie reproposed the project with a new route that would avoid the shellfish beds at some additional cost. Because the first proposal was rejected without prejudice, the revised proposal was filed as a new application in Connecticut, and went through the full review process. The Connecticut Siting council approved the project on January 3, 2002. However, some critics of the project announced their intention to challenge the Council's decision in court.

This case highlights that before filing a formal proposal, an applicant should probe thoroughly for sensitive issues that may be raised by its proposal and the likely impacts of alternative routes. The case also demonstrates the need for states involved in the review of interstate projects to coordinate their reviews and agree on findings regarding the allocation of costs and benefits. (These topics are discussed below in the Regional Prespective section.)

Successes in Siting Transmission

Most transmission siting proposals eventually receive certificates of need. With sustained effort, utilities, state regulators, public advocates, communities, and intervenors usually find answers to problems. A successful review process for a large interstate transmission project is described below.

A recent four-state transmission siting success story

In September 1998, New Century Energies (a company formed by the merger of Southwestern Public Service and Public Service of Colorado and subsequently merged into Xcel Energy) affirmed its intent to build a 300-mile, 345-kV line that would connect a Southwestern substation near Amarillo, Texas, with a substation near Lamar, Colorado, that is partially owned by Public Service of Colorado. From Amarillo, the line would cross the Oklahoma panhandle, continue north to Holcomb station near Garden City, Kansas, and then west to Lamar. The terminus at Lamar was to be a 210-MW high voltage DC interchange facility that would permit asynchronous flows between the eastern and western U.S. grids. The purposes of the project were to improve reliability and stabilize power flows in the region and to facilitate electricity trade. To address potential market power concerns associated with the company merger, Texas regulators required New Century Energies to pursue this project. In July 2001, Xcel Energy obtained the consent from the last of the four states when the Colorado Public Utilities Commission approved the project.

The interest of Texas regulators in this project only partly explains the project's success. Other reasons were the applicant's proactive anticipation of and responsiveness to landowner and community concerns, and the awareness by Kansas regulatory officials of the regional implications of the project and the potentially reciprocal responsibilities of a state faced with a project of principal benefit to neighboring states.

Critical Elements of Success and Conditions that May Lead to Conflict

A review of many siting proposals reveals some indicators of probable success as well as conditions that increase the risk of conflict.

Success indicators

- Link to a generation project—A transmission project that interconnects a needed generation project to the grid is less likely than other types of projects to encounter heavy opposition. The transmission component may be seen as incidental to the generation project.

- Early planning—If interested parties are informed ahead of time that a power line may be needed and will probably be proposed, the project has a greater likelihood of success. In some cases the proposal that is ultimately put before siting authorities differs from that which had initially been presented to the public for review, indicating that the public review was of value.

- Open planning—A planning process is considered "open" or "transparent" when it solicits the views of interested parties regarding ways to address a specific transmission need. Parties other than utilities are more likely to feel that such a process has respected their interests; it also gives the utility the opportunity to make changes to a plan before committing to it as a formal proposal.

- Regional planning—The major benefits from interstate transmission projects are often unevenly distributed. When out-of-state benefits can be recognized in a state's siting process, effective presentation of these benefits is an important indicator of success. Special arrangements may be needed to ensure that a project will provide net benefits to all affected states.

- Demonstrable need—A project appears more compelling as its value to consumers is more evident. The need to maintain reliability is widely accepted although demonstrating that a specific project is needed to strengthen the system can be difficult. The need to interconnect a permitted generator to the grid is usually obvious. In some states, there is debate about the "need" for projects that primarily facilitate electricity trade.

- Economic benefits—If regional energy transfers are clearly in the public interest, a proposed project that enables such transfers will likely be received positively. In some jurisdictions, applying this rationale to power lines is relatively new and results from the increasing importance of wholesale electricity trade. There is debate about whether a proposed transmission line that primarily facilitates electricity trade and reduces electricity costs for some consumers is "needed" (see Regional Prespective section for further discussion). In some jurisdictions, "need" is interpreted narrowly as referring only to reliability.

- Alternatives, presented objectively—Presenting a broad range of relevant alternatives is important. Some states require that alternatives accompany the primary siting proposal, and intervenors and public advocates may develop them if the utility does not. Regardless of regulatory requirements, an objective presentation of alternatives advances the credibility of the applicant and the primary proposal.

- Open lands—If there are few objections to the transmission line route on the basis of natural resource concerns, the odds of a project's success improve, particularly as open land area shrinks in many states with the growth of cities. (Restrictions on the use of much government land limits its value for transmission siting.)

Characteristics of transmission siting proposals/processes that may lead to conflict

- Disregard for directives in law or siting authority pronouncements—Probably the worst thing that a transmission project applicant can do is disregard clear instructions from the siting authority or statute. Although this may seem unlikely, it happens more often than might be expected.

- Differing assumptions about land use—State officials may view proposed land use tradeoffs in ways that differ from utility expectations. An open utility transmission planning process can reveal potential misunderstandings of this kind before they disrupt or derail a mature proposal.

- Potential for disagreements with federal land managers—Difficulties sometimes arise when the interests of one or more federal land management agencies are affected by a proposal. Land managers may not regard accommodating transmission line proposals as a high priority. Different federal land managers within a region may not coordinate well with the state siting process or with each other, even within a single federal department. Federal land managers sometimes decide not to commit resources to participate in the planning of a transmission project (or ignore the process, which has the same result), choosing to participate only after the process is well under way, compromises have been made by others, and the range of options under consideration has been narrowed. Some projects affect the interests of several federal agencies, and some parties cite insufficient coordination among them in reviewing such projects as a problem. (Note: There are also cases in which these managers have cooperated well with each other and with state siting officials.)

Business Uncertainties and the Current Siting Process

The business aspects of the current transmission siting process merit attention. The ongoing restructuring of the U.S. electricity industry poses many uncertainties for the transmission component of the industry. Some companies do not know whether they will remain in the transmission business, and those that intend to stay in the business are unsure what rules will determine the profitability of new transmission investments. There is also uncertainty about how market participants will gain access to transmission facilities, and receive allocations of scarce transmission capacity. The outcomes of these federal legislative and regulatory debates will create winners and losers, and the debates are a consuming preoccupation for participants at all levels of the electric industry.

Some parties believe that many meritorious transmission projects never make it out of the utility board room and into the permitting process. It is unclear whether this is because of uncertainty about whether revenues will cover the cost of the facility, skewed incentives resulting from unsound transmission pricing, fear of the siting process, faulty project development, concern for predatory effects on profits from other utility investments (i.e., generation), other reasons such as local politics, or some combination of influences. The cost of the siting process weighed against the odds of success is understandably important. It is equally important, however, to remember that, in every part of the United States, there is an entity obliged to deliver electricity reliably and at a just and reasonable rate. This obligation does not account for business risk though first principles of regulation call for utilities to be treated fairly by being given the opportunity to collect adequate revenues for their service. These entities must continue to try to build the facilities they believe are needed.

The Regional Perspective

Since the 1970s, electricity providers have increasingly used the nation's transmission networks for electricity trade as well as for the traditional purpose of ensuring the reliability of bulk power supplies. During the past decade, electricity trade has increased very sharply, to the point that congestion is now frequent in many locations and economically desirable trades must often be foregone to avoid loading the transmission lines beyond prudent limits.[14] In addition, as the aggregate economic value of the trade enabled by the grids increases, the trade function becomes increasingly important, and the two functions of maintaining reliability and enabling trade tend to converge. From the perspectives of transmission planning and operations, the overall goal is now to facilitate trade while maintaining reliability.

Although many states do not now take electricity trade into account when issuing permits for new transmission capacity, this may change. In general, all levels of government (federal, state, and local) have long since adopted the policy premise that additional commerce enhances productivity and serves the public interest, assuming that the prices for the goods and services involved accurately reflect real costs. Attention to the externalities or dislocations that could result from trade often leads to requirements for mitigation, and in some cases to outright rejection of proposed additions to an area's infrastructure. Further, if insufficient attention is given to adverse side effects of increased trade, the probability of misallocated or excessive investment goes up markedly. For example, excessive transmission investment could be underutilized because of electrical stability concerns, or excessive investment in local generation could cause generation to be "locked into" a region. A thoughtful assessment of alternatives, as discussed in the section "Improving Agency and Industry Practices," on page E-31, helps to ensure the broad vision necessary to consider all aspects of additional electricity commerce in transmission planning and siting processes.

In any case, given that the policy of favoring increased trade has won broad acceptance, it seems likely that states will increasingly acknowledge the contribution of electricity commerce to the need for new transmission capacity. Given the long-term and forward-looking nature of transmission planning, planners should take into account likely future trade requirements even if some jurisdictions in their area do not now recognize trade as contributing to need. Some analysts note that the reliability benefits of transmission additions are typically distributed very broadly, and the costs of such additions are usually recovered from all con-

[14]New tools for managing the grid may enable operators to maintain reliability standards while reserving less transmission capacity for contingency flows. This will relieve constraints in some areas at some times.

sumers across a wide area; by contrast, the economic benefits of increased commerce may be distributed much less evenly. This means that different methods of cost allocation and recovery may be appropriate, to the extent that a project is needed to support electricity commerce.

Finally, it is apparent that, in general, the public will benefit if the geographic markets across which bulk power trade occurs and reliability is managed are large. This is because large markets tend to be more diversified than small markets, and greater diversity translates into both lower market-clearing prices and lower-cost provision of reliability. (See Issue Papers *Transmission Planning and the Need for New Capacity* by E. Hirst and B. Kirby and *Alternative Business Models for Transmission Investment and Operation* by S. Oren, G. Gross, and F. Alvarado for additional analysis.)

The importance of thinking about bulk power markets in terms of large multistate regions is widely recognized (Fox-Penner, 2001; Bailey and Eaton, 2001; Costello, 2001; O'Donnell, 2000; Stavros, 2000). However, efficient regional markets will not evolve through market transactions alone. Sustained, conscious efforts are needed to develop regional institutions that will support the functioning of such markets. In its Order No. 2000, the Federal Energy Regulatory Commission (FERC) stressed the benefits of large markets; in that and subsequent orders, FERC has emphasized the importance of forming large Regional Transmission Organizations (RTOs). RTOs may be for-profit Independent Transmission Companies (ITCs, also called TRANSCOs), nonprofit operators of transmission facilities owned by others (Independent System Operators, or ISOs), or some hybrid of the two. (For extended analysis of RTOs, see Issue Paper *Alternative Business Models for Transmission Investment and Operation* by S. Oren, G. Gross, and F. Alvarado.) In Order No. 2000, FERC sees large RTOs as essential mechanisms for achieving several transmission objectives that are very important to the public interest, including:

- Provision of nondiscriminatory transmission service to all buyers and sellers in the market area,
- Economically efficient provision of ancillary services,
- Economically efficient assurance of reliability, and
- Regional transmission planning.

Many observers now believe that transmission grids can be planned, built, maintained, and operated most efficiently from a regional perspective. In addition, many are also concerned that the existing state-based regime for siting and permitting new transmission projects may not be well suited to assessing proposals of regional importance. Some of the issues raised are

- The societal costs and benefits of a regionally important transmission project are seldom distributed evenly across the area affected. Benefits tend to be distributed broadly in the form of lower electricity prices, higher reliability, and larger sales volumes for lower-cost electricity producers. By contrast, many costs are distributed narrowly along the route of the proposed line where aesthetic vistas, real estate values, and land use patterns are likely to be negatively affected. In addition, the consumers who pay for the line through their electric bills may or may not be the same group of consumers who benefit from increased reliability

A Case of a Failure to Communicate

The siting proceedings described below for a generation and transmission project that had regional impact demonstrate how communication can go wrong among two states and a federal regulator, and how ignoring a project's regional dimensions in the early stages can cause difficulties later.

In 1989, FERC granted the city of Jackson, Ohio, a license to construct a hydro generation project on the Ohio River. AMP-Ohio, a wholesale power provider to 77 Ohio municipal utilities, joined the project as a co-developer and helped finance the project. A decision was made to site the project at Belleville, West Virginia, to take advantage of a West Virginia law that exempted municipal hydro projects from state tax. However, because the economic benefits of the Jackson project would go mostly to retail consumers served by AMP-Ohio's utility customers, controversy arose in West Virginia where it appeared that citizens would suffer environmental impacts but few economic benefits. Accordingly, the West Virginia Senate passed a bill in 1994 removing the tax exemption for the project and threatening its economic viability. Although the governor of West Virginia vetoed the bill, saying that it was unfair to treat out-of-state municipalities differently from those of West Virginia, an agreement was reached before the veto that the project sponsors would make payments to West Virginia in lieu of taxes and that the transmission line linking the hydro plant to the grid would be located entirely wholly in Ohio even though that would approximately double its length.

In 1996, Ohio regulators approved the transmission line, but Ohio Public Utilities Commission (PUC) chair Craig Glazer filed a "concurring opinion" strongly criticizing the review process and its outcome. Glazer complained that Ohio was not consulted "in a meaningful way" when AMP-Ohio negotiated its deal with the governor of West Virginia: "It is indeed disingenuous for AMP-Ohio to reach an agreement with the West Virginia governor to site the line in Ohio and only then come to Ohio and argue that any routes in West Virginia are not feasible and should not be looked at in the siting process" (*Electric Utility Week,* 1996). Glazer argued that analyses showed "far more environmentally benign and cost-effective routes through West Virginia for this line." He criticized FERC, which had approved the proposed hydro facility, saying that Ohio staff had attempted to establish a joint siting and information sharing process that "fell on deaf ears at the FERC staff level." He continued, "Given FERC's utter lack of interest in such a cooperative effort, [Ohio's] staff did not pursue more formal requests" for cooperation. He added, "This is a case study on how applicants, neighboring states, and an intervening federal agency should not act" (ibid.).

Although there was a good faith effort to resolve the benefit allocation issue between Ohio and West Virginia in this case, the transmission line was not considered at that time by AMP-Ohio, so the company was vulnerable later to the assertion that it had struck an unscrupulous bargain with the governor of West Virginia. PUC Chairperson Glazer noted that some of these difficulties might have been foreseen at the time of the original hydro licensing decision and could have been resolved in advance. Perhaps due in part to this case, Ohio recently adopted a streamlined, time-limited siting process that explicitly provides for cooperation with other states and agencies on siting matters.

and access to lower-cost generation.

- At least one state is legally prohibited from considering out-of-state benefits associated with projects under review (Mississippi State Code 77-3-14). This constraint could lead to rejection of regionally beneficial projects if the intrastate benefits do not appear to exceed the intrastate costs.

- Even if a state is not legally prohibited from taking out-of-state benefits into account, it may still not give these benefits full weight when assessing a project.

- Existing siting processes vary significantly from state to state. Approval may be required from federal agencies charged with the management of public lands; this is particularly frequent in the West. Permits for crossing the lands of Native American tribes may also be needed. Thus, the review process for a major interstate project is almost certain to be complex. Institutional mechanisms are needed to improve communication and coordination among the various agencies that must approve a project and to help develop common procedures and requirements to serve the needs of as many reviewing agencies as possible.

The concerns noted above regarding the adequacy of the existing state-based process for reviewing major interstate transmission proposals have led some observers to conclude that strong regional authorities are needed to organize reviews and decide about siting and permitting of projects that would have regional impacts. For example, see DOE (1998), Recommendation #25: "Explore formation of regional regulatory authorities (RRAs) to provide an institutional focus on interstate transmission enhancement needs, the avoidance of increased regulatory burdens and the replacement of multiple siting and other authorities with single regional siting authorities that are not subject to any state veto." Note: This recommendation was not supported unanimously.

The principal counterargument expressed by organizations representing state and local government agencies is that as yet there is no compelling evidence that such far-reaching changes are needed. In September, 2001, nine state and local governmental organizations delivered a joint letter to Senator Jeff Bingaman, chairman of the Senate Energy and Natural Resources Committee, objecting to Bingaman's draft legislation that would give the FERC a backstop role and eminent domain authority with respect to siting new transmission facilities. The nine organizations were the National Governors Association (NGA), the National Conference of State Legislatures, the National Association of Regulatory Utility Commissioners, the Council of State Governments, the National Association of Counties, the National Association of Towns and Townships, the National Association of State Energy Officials, the National Association of State Utility Consumer Advocates, and the Association of State Energy Research and Technology Transfer Institutions (*Electric Utility Week,* 2001).

An examination of recent or current major transmission projects does not yield conclusive answers about whether strong new regional siting institutions are needed (as opposed to improvements to the existing state-based regime). At a minimum, however, the record confirms that new mechanisms and practices are needed to foster greater coordination, cooperation, and timeliness among states, federal agencies, and tribes that must review proposed major interstate transmission projects. Pertinent issues and policy options are discussed in the sections below.

Some Generic Considerations Regarding the Regional Approach

Before discussing various possible formats for the design of regional siting institutions, it will be helpful to address several background topics that pertain generically to the regional approach.

Relationship between generation siting and transmission siting

Generation and transmission siting are inextricably related. The placement of new generation in relation to load centers and transmission bottlenecks can increase or decrease the need for new transmission facilities. Regional or state planning and siting officials must take these effects into account.

In some areas of the country where natural gas is readily available at low cost (e.g., the Gulf Coast), generation providers have filed applications for transmission interconnections for new generation well in excess of projected load growth in the surrounding area.[15] This generation would serve more distant markets, and additional transmission capacity would probably be needed to enable the generators to reach those markets. However, some parties assert that natural gas pipelines may be generally cheaper and less environmentally intrusive than electric transmission lines, and most analysts agree that new generation capacity should be built as close as practicable to the load centers it serves.

Accordingly, when a new "long line" transmission facility is proposed, opponents may argue that the facility is not needed because new generation could be built near the load center. This would probably raise an evidentiary question (i.e., one requiring formal examination) that would have to be addressed before the question of the need for the transmission facility could be resolved. Further, load centers tend to be heavily urbanized areas; they may have air quality problems; and they may lack the water supplies needed for new generation. Without a thorough assessment of these issues, decision-makers would find it difficult to answer the question of the feasibility in economic and other terms of building a sufficient quantity of new generation near the load center. The need to consider other alternatives to new transmission capacity (e.g. distributed generation)[16] would broaden the analytic requirements of the process even further.

This complex of issues (the merits of local generation and other local alternatives versus distant generation plus transmission) has two significant implications:

(1) It increases the prospects for disagreement between or among states concerning the need for new transmission capacity and suggests that states should be cautious about approving new generation capacity without inquiring whether such capacity may lead to transmission congestion and the need for new transmission capacity in neighboring states. The availability of new technologies for distributed generation and other technological substitutes for new transmission will add fuel to this debate. At a minimum, generation and transmission siting decisions increasingly require extensive communication and coordination among states across a region.

[15]See, for example, comments presented by a Southern Company representative at DOE's workshop in Atlanta, September 26, 2001.

[16]A further difficulty is that it takes time, once a need is identified, to combine the many possible resources into a sound mitigating strategy.

(2) It increases the need for open regional transmission planning processes that will indicate to all affected parties where and when new transmission capacity will be needed, taking into account the siting of generation and the economic cost and feasibility of alternatives to conventional transmission facilities.

Promoting common processes among reviewing agencies within a region

A regional institution could foster the development of common processes that all reviewing agencies in the region—states, Native American tribes, and federal agencies—could use to review transmission projects. The regional body could facilitate development of common application requirements and timelines, joint interagency hearings, agreements on the types of alternatives to be considered, and a single record of decision for the project (see *Conceptual Plans for Electricity Transmission in the West,* 2001). These actions could be accomplished with comparatively little infringement on the authority of the reviewing agencies.

Improving coordination of the overall process in a region

Shortly after an application for siting of an interstate or regionally significant transmission project has been filed with one or more reviewing agencies, it would be beneficial to have a joint meeting involving the applicant and all affected reviewing agencies, including federal agencies and Native American tribes, to identify possible points of difficulty or disagreement and begin exploring possible solutions. Although this meeting could be coordinated informally under the existing state-based review regime, a centralized regional organization could give the effort focused and pragmatic leadership without infringing on the authority of the reviewing agencies.

Two current and controversial transmission siting cases involving Minnesota and Wisconsin[17] provide support for the view that the siting process for interstate projects could be aided significantly if a cooperative regional body were available to assist in coordinating the process, and if regional transmission plans were available to guide state agencies in considering questions related to the need for new transmission facilities. In both of these cases, the applicants contended that the lines were needed primarily to maintain reliability in Wisconsin. The need issue became a matter of debate in both cases, and resolution of it might have gone more smoothly had a well-developed regional plan been available. As of this writing, neither case is resolved.

Providing federal backstop authority

Some designs for regional institutions would give authority for siting decisions to a board composed of representatives from the affected states (and perhaps federal and tribal agencies as well). This raises the possibility of internal disagreement; that is, the regional body might be unable to reach a timely decision on whether a proposed transmission project is needed or on the acceptability of a route for the line. To deal with such cases, after a specified time period or under specified conditions,[18] a federal entity could be empowered to

[17]These are the 38-mile line from Chisago, Minnesota, to Apple River, Wisconsin, and the roughly 230-mile line from Duluth, Minnesota, to Wausau, Wisconsin. The latter has been approved by the state siting authorities, but is the subject of an appeal in Minnesota. The former was withdrawn and is being redesigned based on the results of a mediation process.

[18]One possible condition would be the case of a regional transmission project proposed in a state that declines to consider regional costs and benefits.

Regional Transmission Planning and Development of Cooperative Regional Institutions

Due to the geography of the western U.S., with its comparatively long distances between cities and some of the natural resources used in generating electricity, the western states have gained extensive experience with planning and siting interstate transmission projects. Recently they have begun to develop an institutional framework under the auspices of the Western Governors' Association to aid them in dealing with shared issues related to such projects. Much of this work is being done through a body named the Committee for Regional Electric Power Cooperation (CREPC). CREPC was created in 1984 jointly by the Western Interstate Energy Board, which acts as the energy arm of the Western Governors' Association, and the Western Conference of Public Service Commissions. CREPC has representation from the regulatory commissions, energy agencies, and facility siting agencies in the 11 states and two Canadian provinces in the Western Interconnection. Through CREPC, the western states have begun negotiations to develop a common interstate transmission siting protocol, and are aiming at June 2002 as a target date for a publishable draft.

One of the roadblocks to the formation of comparable institutions in the Eastern Interconnection is the lack of a clear and urgent agenda. That is, without either well-developed regional transmission plans or a collection of actual regional-scale transmission proposals, it is not obvious which states and federal land management agencies need to be talking with each other about what issues. Rather than wait for RTOs to be established and for transmission plans to be developed by them under FERC's direction, an interim approach could be considered. DOE and the FERC could jointly identify key transmission bottlenecks, and FERC could task administrative law judges to work with appropriate parties in each bottleneck area to prepare interim transmission plans. By putting the emphasis on the power of persuasion, such a process would be non-threatening, which would help to elicit constructive responses from stakeholders. The resulting plans would probably flag some important issues affecting groups of states, and thus help to spur the formation of cooperative regional institutions.

rule on the acceptability of the project at the request of the applicant.[19]

The prospect that jurisdiction over a project might pass to a backstop agency after the case proceeds for a certain amount of time could motivate a voting majority of a stalemated regional body to reject the proposal as incomplete before the backstop provision tolls, perhaps in the hope that it would be resubmitted in a form that would win broader support. Further, an agency subject to backstop provisions might be more insistent on the range and detail of alternatives addressed in the initial application, to increase the odds of finding an alternative to which it could say "yes" within the time limit and/or give itself more grounds upon which to declare an application incomplete if necessary.[20] In the end, backstop provisions—linked to time

[19]There are also proposals that would allow applicants to invoke federal backstop authority if a regional entity did not exist and if a state siting agency was not able to make a timely decision about a proposed transmission project.
[20]Note that in the case of AEP's controversial Wyoming-Cloverdale proposal, the West Virginia Public Service Commission (which must rule upon an application within 400 days or else it is automatically approved) at one point rejected AEP's application as incomplete and advised AEP not to resubmit its proposal until after the Forest Service had completed its draft environmental impact statement. Resubmitting the proposal would restart the 400-day clock, and the PSC apparently wanted the clock to start after the Forest Service had issued its impact statement.

limits keyed to a finding that the application meets a specified standard of completeness—would likely lead to the filing of more complete applications and would impose some discipline on reviewing agencies to act within predictable time periods.

Why Not Just Centralize Transmission Siting Under FERC?

There are obvious challenges in coordinating and harmonizing the views of affected states, local governments, tribal bodies, and federal agencies about proposed transmission facilities. Many observers and industry participants have asked whether it would not be better to enact federal legislation making FERC responsible for transmission siting decisions—particularly because FERC already exercises this function with respect to the siting of natural gas pipelines.

Here are some important considerations:

1. Except for areas served by TVA or the federal power marketing administrations, transmission siting is presently a matter of state responsibility. Pre-empting the states and centralizing transmission siting under a federal agency would be a major change, and it is unlikely to win broad acceptance as an appropriate solution to today's siting challenges until less radical measures have been tried and found insufficient.

2. Despite the overarching importance of maintaining the adequacy and reliability of the grid, "all transmission siting is local." Fitting a proposed facility into a landscape where the affected land areas are already used for a wide variety of legitimate purposes will never be easy. Doing this job well will always require an immense amount of information from local, state, and regional sources, as well as consultation and negotiation with and among many of these parties. Transferring transmission siting responsibility to a single federal agency could mean over-centralization, resulting in delays, hasty, or poor decisions, or all three.

3. The existing process for siting natural gas pipelines is not necessarily a model to be emulated. Critics emphasize that some pipeline siting cases have also dragged on for years, and assert that the process is not sufficiently predictable. They also complain that most events in the process take place in Washington, D.C., and argue that this imposes a substantial burden on many participants, and effectively precludes participation by others.

4. Improved coordination of federal agency reviews of transmission proposals would continue to be a major concern, even if siting responsibility were centralized at FERC. However, this problem can be addressed without centralization.

5. As indicated in many places in this report, the FERC already faces a long agenda of important and urgent matters related to establishing and maintaining effective competition in the nation's bulk power markets. Many of these matters, in practical terms, can only be addressed by FERC—there is no other credible candidate. In the case of transmission siting, however, the states still want to do the job.

A stronger but much more controversial formulation of the backstop concept that has been proposed by some in the electric industry would be to empower the applicant to appeal to the backstop agency when a reviewing agency acts within the allotted time but rejects the application. This version would be much resisted by the reviewing agencies because it makes the state process appear less important to the ultimate decision on the application. It is also unclear how this structure would actually change the nature of the review process. It might make it more difficult for a reviewer to say "no" to an applicant, knowing that the applicant could turn to the backstop agency for a second opinion, or it might tempt a reviewer to reject a controversial project anticipating that the backstop agency may be more willing to take any political heat associated with approving the project. A pernicious effect on the behavior of applicants could be the emergence, at least in some cases, of "forum shopping." That is, some applicants could become less responsive to the concerns of the reviewing agencies and less willing to spend money to address their concerns, knowing that if they got a rejection they could turn to the backstop agency.

Over time, the criteria and standards used by the backstop agency would tend to become definitive for all reviewing agencies, perhaps making the role and powers of the backstop agency more important than the drafters of the backstop provisions had realized or intended.

Responsiveness to local concerns

A frequent criticism of the regional approach, especially if it is combined with federal backstop authority, is that a regional or federal body will not be sufficiently responsive to local concerns. To address this issue, a regional or federal body could be required to hold extensive local public hearings and weigh the concerns expressed at these hearings against regional and national ones. Historically, many regional federal entities (e.g., the Bonneville Power Administration, the Tennessee Valley Authority, regional offices of the Environmental Protection Agency) have proven to be very responsive to local concerns (sometimes to the consternation of officials in Washington, D.C.).

Should regional bodies be empowered to provide sdvisory opinions only?

Giving regional entities the power to counsel but not decide would have the advantage of enabling a panel of experts to provide an objective assessment of a proposed project from a regional perspective without infringing upon the reviewing agencies' powers of decision. The reviewing agencies would be under some pressure to explain decisions not compatible with a regional body's advisory opinion. The disadvantage of this approach is that it further complicates rather than simplifies the institutional landscape for transmission siting. Many parties are strongly opposed to adding new layers to siting procedures or electricity regulation.

Risk of jurisdictional confusion

If a regional siting body were established, states in the area would still likely retain jurisdiction for some new transmission projects, depending on the definition of "regionally significant" used to identify the projects over which the new body would have jurisdiction. If the definition relied on clear empirical criteria (e.g., "all transmission projects of 230 kV or higher"), the jurisdictional boundaries would probably be clear, but there would still be some practical difficulties with the empirical approach. (See the section "Defining 'Regional Transmission Facilities,'" on page E-25, for further discussion.)

Risk of "forum shopping"

An applicant might deliberately design a project to fall into one jurisdictional category rather than the other, e.g., so that the body that the applicant perceived to be most favorably disposed would review the project. This might in some way disserve the public interest. As long as both reviewing bodies are reasonably well conceived and well run (and these are not trivial requirements), the public interest should be adequately served.

NEPA reviews

If a regional body with siting authority included some representatives of federal agencies, this raises the question of what level of federal involvement would trigger the requirement for an environmental assessment or environmental impact statement under the National Environmental Policy Act (NEPA). If a decision by the regional body would supplant the need for an independent review of the project by one or more federal agencies, it seems likely that the regional body would have to conduct an environmental assessment. Depending on the results of the assessment, an impact statement might be required. In general, major new transmission projects usually have significant environmental impacts; in such cases, if federal decisions are required, full environmental impact statements must be prepared.

Alternative Designs for Regional Siting Institutions

There are at least five basic designs that might be considered for regional siting institutions, and many possible hybrids among the basic models. The discussion below focuses on the principal distinctions among the five basic models and is not intended to be exhaustive.

Cooperative agreements

A cooperative agreement would establish a regional entity for the mutual convenience of participating states, tribes, or federal agencies; the participating agencies would not cede any existing authority or responsibility to the regional institution. The regional institution's functions would be limited to activities such as fostering common siting processes and requirements and improving coordination among members to streamline review of regionally significant transmission facilities. Members would probably find it useful to agree on a category of facilities that would fall under the entity's purview, and they would have to agree on how to staff and fund the institution. The parties could begin by establishing a cooperative agreement that would apply only to one specific major case and then decide on the basis of that experience whether to continue to proceed case by case or to establish a standing agreement.

Interstate compacts

An interstate compact is an agreement among or between states to establish an institution that has the power to act for all of them in a specific area. Establishing an interstate compact is a complex process, especially if more than a few states are involved. The legislature of each participating state and the U.S. Congress must approve the compact's founding agreement.

For a compact on transmission siting, many states might have to enact legislation to authorize their public utility commissions (PUCs) to cede specific authority to the regional body or to share authority or provide guidance to the commission concerning the circumstances under which it should defer to the regional body. The founding agreement would have to define the class of transmission facilities that would be subject to the commission's jurisdiction and establish how the commission would be staffed and funded.

Agreements for compacts typically specify that the governors of the participating states will appoint the compact's commissioners. Voting representation on a compact commission tends to be controversial because of differences in the sizes of states and how to set each state's share (e.g., based on population or contribution to gross domestic product) as well as the likelihood that some states would probably be more affected by the commission's activities than others. Smaller states tend to prefer one-state, one-vote structures so as not to be overruled by larger states.

Interstate compacts have been established for many purposes, and some have been much more successful than others. They ultimately depend on cooperation and goodwill among the member states. If states are strongly at odds on an issue, a compact commission may find it difficult to solve the problem. Conceivably, a provision for federal backstop authority could be included in the founding agreement to deal with potential stalemates.

Another possible problem with the compact model in the current context is that federal agencies are not subject to interstate compacts. Cooperative agreements could be devised between a compact commission and appropriate federal agencies, but the arrangement would be comparatively informal. Another question is whether the founding agreement could be fashioned to facilitate participation by Native American tribes.

Independent regional entities

The independent regional entity model offers considerable flexibility (regional authorities have been established through federal legislation to address a wide range of problems).[21] Affected agencies (state, tribal, or federal) would have to agree on a conceptual design for a regional authority that would accomplish their common purposes, and then appropriate federal legislation would have to be crafted and enacted to serve those purposes. This approach requires the support of most of the affected states, but it is significantly less formal than the process for establishing an interstate compact.

Presumably, a board of commissioners would head a regional authority, and the enabling statute would set the criteria for appointment to the board. One approach would be to use the siting boards that currently exist in some states as a model, with commissioners from relevant state and federal agencies or tribal institutions nominated by governors, tribal authorities, or the President.[22] Thus, this model accommodates federal participation more readily than an interstate compact. The designers of the new entity would have to decide how best to balance federal and state interests, particularly with respect to voting powers and whether there would be federal backstop authority.

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[21]This model probably comes closest to accommodating the intent of the Task Force on Electric System Reliability to the Secretary of Energy Advisory Board in its Recommendation #25. (See DOE 1998).

[22]A critical design element would the process for removal of commissioners from the regional board. Serving at the pleasure of the appointing authority is quite different from serving for a distinct term, for example. Another significant matter to address is how such an organization would be staffed.

As with the other models, designers would have to define the class of transmission facilities subject to the new entity's jurisdiction and establish a funding mechanism. If the new entity were to have final siting authority on behalf of federal agencies, the enabling legislation would have to amend the enabling laws for those agencies. Similarly, state legislatures would have to make appropriate changes to their respective siting laws. A sunset provision could be included to ensure future review of the need for and effectiveness of the new entity.

Joint federal-state boards

Although there are precedents in the telecommunications sector for the establishment of joint regulatory boards, this model has not been used in electricity regulation despite periodic expressions of interest by the National Association of Regulatory Commissioners (NARUC) and various states. Further, the relevance of this structure to transmission siting, at least under existing law, is at best uncertain.

Section 209(a) of the Federal Power Act authorizes FERC to refer an electricity matter under its jurisdiction to a joint state board composed of nominees selected by the respective state utility commissions or by the state's governor if there is no state commission. A joint board is to have the same power, duties, and liabilities as a commissioner at FERC who has been directed by FERC to hold hearings. Thus, a joint board for an electricity matter, assuming unanimity among its members, would be equivalent to a sixth commissioner at FERC with respect to FERC decisions on the matter.[23]

However, under current law, FERC has no jurisdiction over transmission siting, so it would have no basis upon which to call for the establishment of a joint board to address transmission siting issues.

Regional FERC offices

FERC could be directed through federal legislation to establish offices in each RTO's area; each office could be made responsible for transmission siting and rate regulation within the region. Such legislation could limit FERC's regional activities to matters such as hearings before administrative law judges and staff reviews of siting applications and could reserve final decision authority to the commission. The legislation could also direct FERC regarding the creation of regional joint state boards on transmission siting, the weight to be given to decisions by such boards, and how FERC's siting decisions should take into account the views and expertise of other federal agencies and Native American tribes.

[25]The full text of Section 209(a) reads:

> [FERC] may refer any matter arising in the administration of this Part to a board to be composed of a member or members, as determined by the Commission, from the State or each of the States affected or to be affected by such matter. Any such board shall be vested with the same power and be subject to the same duties and liabilities as in the case of a member of the Commission when designated by the Commission to hold any hearings. The action of such board shall have such force and effect and its proceedings shall be conducted in such manner as the Commission shall by regulations prescribe. The board shall be appointed by the Commission from persons nominated by the State commission of each state affected, or by the Governor of such State if there is no State commission. Each State affected shall be entitled to the same number of representatives on the board unless the nominating power of such state waives such right. The Commission shall have discretion to reject the nominee from any State, but shall thereupon invite a new nomination from that state. The members of a board shall receive such allowances for expenses as the Commission shall provide. The Commission may, when in its discretion sufficient reason exists therefore, revoke any reference to such a board.

Defining “Regional Transmission Facilities”

If regional transmission siting entities were established, the category of facilities subject to the jurisdiction of these bodies would probably need to be defined. The subsections below address possible criteria for this definition and the institutional context in which they might be applied.

Objective Criteria

One way to define the transmission facilities that would fall under the jurisdiction of a regional siting body is to use objective indices, such line voltage or length or whether the line would cross state boundaries. Although these criteria may sound reasonable, they may not always yield the expected results. For example, in some sparsely populated areas, lines that serve transmission functions may be comparatively low voltage; conversely, in some densely populated areas, distribution lines may be designed for economic reasons to operate at high voltages. Another example is that a facility may be used in part for transmission and in part for distribution purposes. One way to deal with problems of this kind is to create a definition based on objective criteria with a mechanism that would allow an affected party to petition for a waiver, based on demonstrating that the criteria should not be applied in a specific case.[24]

Functional Tests

An alternative for defining the jurisdiction of a regional body is to apply functional tests that gauge whether a facility would be used primarily or wholly for transmission and define the degree of its expected contribution to the reliability of the regional grid. A significant objection to this approach is its lack of transparency—applying it could require hearing and evaluating evidence before a decision could be made about whether a proposed facility is regionally significant.

Economic Test

An economic test could be devised to estimate the probable economic benefits that a line would provide for consumers over a given period through either improved access to lower-cost generation or mitigation of potential market power. This estimate could be compared to an agreed-upon threshold for determining regionally significant projects. This approach might also require gathering and evaluating evidence.

In short, there are no easy, straightforward criteria. However, determining the criteria would be more important in some institutional contexts than others. For example, if the institution’s principal function is to facilitate cooperation among the reviewing agencies in the region, if the agencies retain their existing authority, and if no federal backstop mechanism is established, then no jurisdictional changes would result from the designation of a project as a “regional project.” A “regional project” would be channeled through the regional cooperative process, but no other changes would ensue. As a result, the criteria for determining a regional

[24] Many states currently use objective criteria (such as voltage and line length) to determine whether transmission distribution projects need state approval. Projects that do not meet the defined threshold in these states still have to meet local zoning, safety, and other requirements, but they do not have to go through the full state siting review process.

project would be less important (and less likely to be the focus of litigation) than if designation as "regional" would mean that a project might under certain conditions be shifted onto a federal jurisdictional track. As long as jurisdiction would not be affected, the most important choice the reviewing agencies would have to make could be whether they wanted to channel all transmission projects through the regional body, or only a subset of projects deemed to have regional significance.

By contrast, if the regional institution was given the power to decide siting questions, the scope of its jurisdiction would be much more important, and the founding parties would probably wish to define criteria for jurisdiction very carefully. Similarly, if a federal backstop mechanism were created by federal legislation, the legislation would probably have to address jurisdiction. One approach would be to sidestep the criteria altogether and specify that under certain conditions (e.g., failure of a reviewing agency to act within a specified period, or rejection by a reviewing agency of an RTO-approved transmission project), the applicant could petition the backstop agency to take the case. Another alternative would be for the legislation to direct the backstop agency to conduct a rulemaking procedure to establish appropriate criteria for identifying transmission projects of regional or national importance.

Improving the Existing State-Based Siting Process

Regardless of how the debate evolves over whether regional or federal authorities should be responsible for certain aspects of transmission siting, states will continue to be responsible for siting a large proportion of the nation's new transmission facilities. Thus, it is worthwhile to consider how the state-based siting process could be improved.

Transmission proposals fall typically into one or more of three categories:

- Those needed to connect a new generator to the grid,
- Those needed to meet reliability standards, and
- Those needed to enable increased electricity trade.

Some projects are very small in geographic scope; others extend for hundreds or even thousands of miles.[25]

Although there is debate about the scope of possible federal or regional responsibilities for transmission siting, state authorities will continue to review dozens of transmission or transmission-related proposals each year, and responsibility for siting generation is likely to remain with the states. Similarly, most legislative proposals that would shift some jurisdiction for transmission siting away from states (e.g., transfer a "backstop" authority to FERC) nonetheless leave states with the primary authority for this function. State-based transmission siting processes vary considerably across the U.S., and, for the most part, worthy projects are approved, and deficient projects are discouraged, improved, or rejected. Most transmission projects are intrastate and small in scale.

[25]A recent proposal (not yet filed at a siting authority) would build approximately 2,000 miles of transmission lines to connect new coal generation in Wyoming with load centers in Chicago and Los Angeles.

Even successful siting cases may have shortcomings, and some cases illustrate recurrent criticisms of state-based transmission siting that warrant attention. Some observers believe that the cases that could have been handled better represent exceptions to a basically sound system. Others see these cases as symptomatic of a need for fundamental changes.

Accountability

Any system of regulation must have and retain public confidence. Generally, regulators earn public confidence by being fair, competent, and consistent over time. In the United States, the general practice is to assign responsibility for regulation to the level of government that can most effectively serve and protect the interests of the citizens affected. This practice allows local conditions and differences to be reflected in regulatory decisions, and non-local considerations can be taken into account when appropriate.

Improvements to Siting Processes

State laws governing transmission siting are the product of serious debate among elected officials. Likewise, state siting decisions are the products of a careful weighing of evidence in light of public policy expressed in statutes. Although state siting laws and processes have been conscientiously developed, improvements may be needed to maintain a reliable and adequate electricity grid. Some possible changes are discussed below.

"One-stop" siting process

Some states place the authority for considering transmission siting proposals in a single agency, which may be the state regulatory utility commission or a siting board made up of decision makers from several government departments. This structure makes accountability for siting decisions clear, and it enables applicants to become familiar with a single process. If local authorities have a role in the approval process, it is important that the state be able to impose on all local reviewers a common, statewide perspective regarding the regulated utility system.[26]

Interstate projects would be eligible for one-stop treatment only if the affected states combined their efforts into a regional siting process. This principle has many supporters, but the procedural requirements would be very demanding; the authors are aware of no successful attempt at a voluntary, one-stop, multi-state siting process.[27] The dilemma for states is often thought to be whether the state siting authority should focus exclusively on protecting the state's interests or should take an expansive view and consider regional interests. This is a false choice. The long-term interests of most consumers are best served by addressing regional grid needs while accounting for state interests at the same time.[28]

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[26]For example, recent legislation passed in Colorado modified the standing of local authorities in transmission siting matters. The PUC can now pre-empt the decision of local authorities if there is a compelling state interest.
[27]Ohio has a statute that explicitly authorizes its transmission siting authority to cooperate with other states, but this process has yet to be tested. The western states have begun negotiations concerning a common interstate siting protocol for the west, which could result in something like a regional one-stop process.
[28]There are many examples of state siting orders that make a special effort to acknowledge the importance of regional concerns. There are also examples that do the opposite.

Three Views of State-Based Siting

Three organizations with distinctly different perspectives about U.S. electricity policy are the Western Governors' Association, the Edison Electric Institute, and the Electricity Consumers Alliance. Although many parties have views about how to change the transmission siting process, the views of these organizations illustrate that there is a broad range of opinions.

The Western Governors' Association (WGA) is a policy forum serving 18 western states, including Alaska and Hawaii. The organization has a long-standing interest in transmission siting and energy policy. The WGA position is:

- Transmission expansion should support three key priorities: enhance reliability, reduce consumers' costs, and promote fuel source diversity.
- Need should be established using regional criteria.
- Siting should remain the responsibility of the states.
- The states should collaborate in the review of interstate transmission projects, and federal land management agencies should join this collaboration.

The Edison Electric Institute (EEI) is a trade association that represents the interests of investor-owned electric utilities. The EEI position is:

- States should have a limited amount of time to review any transmission project.
- If a state rejects a project or does not rule within the allotted time, FERC should be authorized to take the case as it stands and rule upon it within a specific time period.
- Other EEI recommendations concerning federal land management agencies focus on enhancing coordination and attention to deadlines in agency reviews of siting proposals.

The Electric Consumers Alliance (ECA) addresses electricity policy issues nationally and in key states on behalf of small consumers and their local organizations. The ECA position is:

- Determination of need for new transmission should be made by a regional transmission organization.
- Federal, state, and local reviews should take no more than 12 to 18 months.
- Reviews by more than one agency within a single state should be combined. Similarly, reviews by more than one federal agency should be combined.
- If federal or state reviews are not complete after the allotted time, FERC should take and rule on the case.
- The rights of individuals must be respected in the siting process.

Sources: The Western Governors' Association published its views in *Conceptual Plans for Electricity Transmission in the West,* 2001). The Edison Electric Institute (EEI) is a trade association for investor-owned electric utilities. EEI's views were conveyed to the authors in a personal conversation with Rich Loughery and Henry Bartholomew. The Electric Consumers Alliance (ECA) represents hundreds of rural, senior, low-income, small-business, minority and other consumer organizations. ECA conveyed its views at a DOE public hearing on September 28, 2001.

States will also need to address the allocation of costs for a regionally justified transmission project. An RTO or a tightly operated ISO[29] will administer this matter once the project is built but typically does not have an active role at the project review stage. If there is a problem with the allocation of costs and benefits among states and their consumers, these money matters should be negotiated under pressure from regulators (as they often are in natural gas open-season proceedings).[30] Siting authorities can send signals to developers and allow reasonable time for proposals to be adjusted to address such concerns. Authorities can also encourage project planners to address this subject with stakeholders and the public before an application is filed.

Ex parte rules control how information flows to and from the regulatory body; they are intended ensure a fair process free of abuses by parties who have ready access to decision makers. The evidentiary basis for an order should be clear from the record. However, ex parte rules can hinder the management of siting dockets and negotiations with the applicant or other reviewing agencies by shielding the siting authority from valuable insights more likely to emerge in conversation than in cross-examination. Beyond speaking through their orders, regulators can find ways to communicate constructive information in a fair way, using methods such as workshops, special masters and other alternative dispute resolution methods, written questions to the parties, status orders, etc.

Maximum time limits

Most transmission siting proposals are small in scale and are reviewed and acted on by the relevant state authority within a year. Larger projects attract more attention from intervenors, are more complex, and may take longer. In some protracted cases, the siting authority may, because of reluctance to reject a project that appears to have merit but needs modification before it can be approved, allow the applicant time to correct deficiencies that emerge during the proceeding.

In general, however, siting authorities should strive to maintain schedules and avoid delays. Among other things, this means not allowing opponents of a project to hold up the process. Opponents must have a fair opportunity to gather information and present a case but should not be allowed to take control of the calendar. The project proponent can help prevent this kind of delay by presenting a credible array of alternatives so that opposing parties cannot obstruct proceedings by calling for inquiries into reasonable alternatives that have not been addressed in the proposal.[31]

As an alternative to allowing the siting review calendar to be based on judgment calls, some states impose a time limit on the process. However, if a time limit is to have a positive effect, the time allowed must be sufficient for a review that will meet public expectations for thoroughness and fairness. A very tight time limit can too frequently put the authority in the difficult position of nearing the deadline with inadequate evidence to find in favor of a project. A system that frequently results in rejections on procedural grounds or approvals by default is not a good system.

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[29]A tightly operated pool is one that controls and dispatches all the generators to reduce overall costs, and internalizes numerous cost allocation decisions in its rate structure.

[30]The April 2001 Connecticut Siting Council decision to reject the Cross Sound Cable project included a warning, presumably directed at successor proposals regarding the allocation of costs as compared to the expected benefits.

[31]Of course, if there is a superior alternative, the process must accommodate it. Proponents of transmission projects should do their best to ensure that there are no superior alternatives and expect the review process to ratify that view.

A recurrent complaint from prospective applicants is that siting processes without time limits are too unpredictable. For example, unpredictable time frames can negatively affect project financing; an applicant may be reluctant to spend the money to develop a proposal and support it through the approval process unless it is reasonably certain that it will be able to obtain financing for the construction phase of the project. However, potential financial backers may be unwilling or unable to address the financial details of a project if they do not know when construction might begin or be completed, and a project tied up in a protracted review is more likely to be adversely affected by ongoing changes in bulk power markets. Reasonable time limits on transmission siting processes would help dispel the uncertainty that appears to hamper many business decisions in the transmission sector.[32]

Clarify approval criteria

Fortunately, many transmission proposals that come before siting authorities address unambiguous needs to improve reliability or to respond to growth. The difficult cases are ones in which the facts do not line up well with the approval criteria, or the criteria themselves are inadequate for the specific situation. States should examine the approval criteria in their siting statutes in light of the significant changes occurring in bulk power markets (see "The Regional Perspective", on page E-13). In addition, when a case exposes a weakness in the statute, this should be addressed by the state legislature as soon as possible.[33]

Cost recovery rules and grid investment needs

Utility costs cannot be recovered from consumers without rate proceedings. Many utilities' rates are frozen or capped for long periods as part of a regulatory agreement, as imposed by a legislature in electric restructuring laws, or for punitive reasons. Without performance incentives or the opportunity to recover extraordinary costs, a utility may decide to avoid major investments even when they are needed. When considering rate freezes and caps, regulators and legislators should consider the horizon of prospective utility investments and consider whether a cap will stifle important projects.[34]

Federal incentives for state changes

In some instances, state siting processes based on an accumulation of law and precedent may no longer be adequate to address the challenges associated with the current restructuring of the U.S. electricity industry.[35]

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[32]A complete proposal, based on standards established by statute and rule, is key to making a time limit work. Until a proposal is complete, the "clock" should not start.

[33]Legislators are sometimes reluctant to "open up" a statute for fear that others will take the opportunity to press for other changes. This concern must be balanced against the need to update an important process.

[34]Utilizing traditional regulatory tools like Construction Work in Progress accounts or simply booking and deferring costs for future regulatory treatment can provide utilities with assurance that they will recover the costs of needed transmission investment incurred during a rate cap, including a reasonable return on investment after the end of the rate cap. However, if the cap is part of a performance ratemaking plan, and the utility has accepted the risk that such costs may be needed during the period of the plan, then asset depreciation would start normally, and the utility could include the depreciated costs in the consideration of post-plan rates. In this latter case, utilities would still have incentives to pursue cost-effective transmission investments because efficiency improvements inure, at least in part, to the utility's profits in performance based ratemaking.

[35]This subject requires extensive analysis and lends itself to the "best practices" project discussed below in "Federal Assistance."

Given the arcane nature of transmission siting and the potentially difficult political challenge of updating the siting process, the federal government may be able to facilitate needed change by means of incentives.

Federal sponsorship of workshops and development of model legislation are worthwhile approaches; another initiative that has significant support would put the Federal Energy Regulatory Commission in a backstop role to state siting authorities. This approach, which would require changes in federal law, would give FERC siting jurisdiction over proposed "regional transmission facilities" (See section on "Defining 'Regional Transmission Facilities,'" above) if affected states fail to act within a specified period.[36] Many observers expect that if FERC had this role, most states would intensify and coordinate their efforts and complete reviews in time to avoid an unwanted change of venue to the backstop authority.

An approach that some observers find less aggressive would be for federal law to support or assist the formation of cooperative regional bodies composed of officials from affected states; these regional bodies could be convened to coordinate the review of regionally significant transmission proposals. (This idea is explored in the section "The Regional Perspective," above.) These regional institutions could be aided by findings of need from the soon-to-be-formed RTOs. The question of what authority states should retain in future siting processes is currently stalemated between advocates of state authority and proponents of federal authority.

Improving Agency and Industry Practices

Not all barriers to siting of new transmission lines are related to the state-based review process. Some delays and rejections result from omissions or other types of problems with transmission proposals or with the practices of transmission owners. The subsections below address changes in practice by prospective transmission siting applicants that could improve the quality of regulatory outcomes.

This section also turns attention to the federal government, addressing siting on federal lands, siting by federal utilities, and other actions the federal government can take to improve siting results.

The subjects in this section are linked by improving methods, utilizing existing methods better, more effectively deploying new methods, and communicating among all affected parties more effectively. A positive outcome would be one in which the transmission owners' interest and the public interest are better aligned than they appear to be today.

Effective Presentation of Alternatives

Transmission siting proposals are complex, especially for large-scale projects designed to improve reliability or enable increased energy transfers over wide regions. To aid decision makers in making a sound choice

[36]FERC backstop authority could also be exercised if state siting authorities addressing a regionally important multi-state project disagree on whether the project should be permitted. This is different from a trigger based on a time deadline because in this case the states would have executed their responsibilities. FERC could determine whether some compromise or blending of interests among the affected states would be possible.

about whether to permit a project (and to prevent critics from derailing a project by shifting attention to other options), a proposal should include a detailed presentation of the alternatives considered.[37]

Alternatives enhance credibility and public confidence

A proposal that presents and compares alternatives shows that the proponent is focused on meeting a system need in the best way, not on getting a particular project built. Addressing alternatives shows the applicant's confidence that the proposal represents the best approach to meeting a system need. This approach can be aided by undertaking an open planning process once a need has been recognized but before a solution is selected; the public should be engaged in this process to assist the transmission company in combining its own and public interest priorities in the decision process.[38] This process improvement should not be used, however, as a way to shift the responsibility to develop alternatives to intervenors. Many permitting agencies already require that proposals include alternatives. Agencies that do not should consider adding this requirement as an investment to speed the overall process.

Range of alternatives must be broad

Even when an applicant presents alternatives, the range addressed may be too narrow. Efforts to define a generic list of alternatives that should be addressed are difficult because of the inherent variety of grid needs and circumstances. Instead of mechanically addressing a list of required alternatives, an applicant will likely fare better by determining what alternative routes or alternatives to transmission are likely to be considered relevant by the regulators and potential intervenors and addressing these options in detail. (The applicant will readily learn about these alternatives during a transparent planning process.)

If important alternatives are not evaluated in the proposal, they are likely to be introduced by public advocates or other intervenors who may assert that the alternatives represent a better approach than the proposed project.[39] It is also worth adding that a transmission line serves no other purpose than to conduct power, but other options such as increasing energy efficiency, managing load, and constructing local generation, may have distinct, positive externalities in the community while also contributing to reliability. Franchised wires companies are usually concerned with the general economic well-being of their service areas, so they have reason to consider a broad range of potentially beneficial local investments.

Advantages of Open Planning

A frustration that is sometimes expressed in the midst of a transmission siting dispute goes something like this: "If only the applicant had spoken with us before going public with the proposal. Now both sides are digging in for a fight." Costly proposals to build new lines sometimes seem to come out of the blue because

[37]This is not usually a concern for transmission that will interconnect a generator with the grid.

[38]Southwestern Public Service, then a subsidiary of New Century Energies, conducted such an open process in building a transmission line in Kansas. As a result the Kansas Corporation Commission approved the segment of the project in its state despite the lack of direct and immediate benefit to Kansas. (Personal communications with Mark Doljac, Kansas Corporation Commission.)

[39]An example is a transmission project in New Mexico that was rejected after local generation and efficiency alternatives were proposed by the state Attorney General and other intervenors.

needs are not articulated ahead of time, if ever; once a transmission corridor is proposed, land owners and other interested parties may feel as if set upon by a powerful force.

It does not have to be this way. Although some parties will oppose power line proposals regardless of the circumstances, others may be moved to oppose a project not so much because of its content but because of perceptions that the proponent is behaving in an arrogant or paternalistic fashion or making a unilateral decision. Despite the costs of regular reports to the public about the state of the transmission grid and its expected needs, it is in the interest of both the public and the applicant or RTO to make these reports. System needs can be tracked as they evolve from technical indications into demonstrable problems. Discussions about how to address growing concerns can be particularly productive if they involve affected parties and all relevant information is available to anyone who cares to look for it. Early identification of potential problem areas also allows small-scale responses like distributed resources the best opportunity to contribute efficiently to a solution.[40]

Deterministic and Probabilistic Planning

Deterministic analysis identifies possible events (e.g., failure of a large generator) and studies their effects on reliability. The analyst assesses the likelihood of these events based on professional judgment. Probabilistic analysis uses a rigorous statistical method to assess the likelihood of an event and its effects. Probabilistic analysis allows for relatively easy numerical comparisons of alternatives, but these comparisons may seem more precise than they actually are because the results are highly dependent on the quality of forecasts of future equipment performance. Deterministic approaches are more traditional and less costly. Both methods are valuable. Regulators should encourage the use of both so decision makers can have the most complete information possible.

Impact of Rate Design on Decision Making

As its participants know well, there are many ways to regulate the electric utility industry. The rules and rate designs in force at any given time affect the decisions and behavior of the players. Some examples follow showing the effects of rate design on the assessment of new transmission proposals:

- If the cost of a new transmission project is “rolled in” to average regional transmission rates, the new transmission will be far easier to justify than if the same costs are assigned only to the group of consumers in the region whose changes in electricity usage have caused the investment to be necessary.[41]

[40]A related topic is that the grid in which investments are made today will not be the same grid in just a few years. Loads will change, new generation will be built, and some units may be retired. One merit of a transparent process is that it helps focus on the investments that are most likely to make sense for a wide variety of futures.

[41]A corollary to this idea is drawn from experience with highways. If new roadways are built to address congestion without addressing lower-cost ways to reduce traffic, and if the source of the demand for the new roadways does not pay the cost for the new construction, the new road can generate more traffic. That is, more traffic than expected will use the new roadway because it is available, and congestion will increase more rapidly than highway planners would have predicted based on prior patterns. Similarly if a new remedial connection to the grid is built and the costs are assigned to society rather than to the connection’s direct beneficiaries, the connection can result in increased demand (either from inefficient generation siting or even greater volumes of long distance energy trading) and therefore increased congestion. Some would call this an implicit subsidy. The result of this scenario is increased congestion, much more rapidly than would be expected based on prior patterns.

- If the costs of an alternative are treated as rolled in while the costs of competing alternatives are charged incrementally to those whose energy use has caused the need for the new transmission, the utility will tend to select the alternative whose costs are rolled in even if it is more expensive and less effective at meeting grid needs.

These are not hypothetical examples. The first case is typical in the New England Power Pool (NEPOOL), where the cost of "pool transmission facilities" is borne by all consumers in New England. Although these facilities are not intended as local interconnection service and are in principle necessary for reliability, their need is often the result of demand growth in a distinct part of the whole region. Nonetheless, everyone pays. The second case is typical in most regions. Distributed resources such as energy efficiency and local generation are the best answers to some grid problems. Yet the system-wide financial support available for transmission to assist the grid is not available for these competing alternatives. Basic economics suggests that when the cause of an investment can be clearly be assigned to a specific group of customers, those customers should pay for it. Implementation of this rule by regulators is complex in practice though congestion transmission pricing is a very positive step in this direction. Ignoring this rule will adversely affect the nature and efficiency of future utility investments.[42]

Encouraging Innovation

One way that the transmission siting process can be improved is for regulators to reward applicants for bringing forward innovative ways to address transmission grid needs. There is evidence of this already, as DC proposals, undersea projects, and flexible AC transmission system (FACTS) devices begin to appear on grid expansion plans. Industry and DOE should continue their attention to the pace and direction of transmission-related research and development, and the industry should continue to educate regulators about the merits of new approaches and devices that can enhance the grid.

Effects of Cost Minimization

Some parties are critical of existing regulation because returns on equity investment are thought to be inadequate compared with the risks of the enterprise and the value added by transmission facilities. In this view, transmission costs are roughly 10 percent of retail electric rates; a modest increase over this figure should be acceptable to consumers if the result is greater incentive to propose needed projects. Allowing higher proposal costs would also tend to widen the range of economically competitive alternatives.

At the same time, applicants sometimes resist adding features to their projects that would increase costs but bring the proposals in line with public policy concerns. Examples of such features include:

- Selective undergrounding,
- More attractive tower designs and wire placements,

[42]This idea can be extended to the retail regime as well. The State of Connecticut directs system benefit funds to support demand-response programs in designated transmission- and distribution-constrained areas. (Also, see Moskovitz, 2001.)

- Longer routes around sensitive areas,[43]
- Zigzag corridors as an alternative to long, straight wooded corridors, and
- Sharing of more financial benefits with affected landowners.[44]

Some might suggest that these elements "gold plate" a project. Others see these features as real costs necessary to win support and fit a needed project into surroundings that are not blank slates but lands protected by legitimate property rights and valued by society. A transparent planning process that focuses more broadly on addressing future needs will aid applicants in identifying beneficial improvements to budding projects.

Need for Complete Applications

Transmission siting is a difficult process at best. When a proposal is incomplete, the process becomes still more difficult. The reasons for incomplete applications range from a lack of familiarity with the rules and expectations of the siting authority to intentional omission of significant information. In any case, the burden is on the applicant to know and abide by the spirit of the rules. This is not just an issue of fair play; trust is a fragile commodity in a process where the threat of eminent domain always looms, even though it is rarely mentioned and even more rarely used. When applicants do not abide by the rules of the process, they may lose the trust of the public and the siting agency. Once trust has been compromised, it is difficult for a review process to reach an outcome that will be in the public interest and be so recognized by most parties.

Transmission Company Perceptions of the Siting Process

In some jurisdictions, there is anecdotal evidence that at least some transmission system problems are not being addressed because utility executives are concerned about the hostile reception they expect that proposals would receive from the state siting process.[45] Utilities holding this view assume they would lose in the court of public opinion and waste financial and human resources in the attempt. It is difficult to evaluate these anecdotes for several reasons. A utility speaking freely and acknowledging reluctance would risk a regulatory ruling that it had been imprudent for failing to pursue construction of needed facilities. Further, the root cause of the reluctance may relate to factors other than the siting process. The existence of these stories, however, is clear indication of a problem. One objective of reform of the siting process should be to ensure that the process is perceived as welcoming good proposals and offering a fair test to all projects. A process in which utilities with an obligation to deliver are so intimidated that worthwhile projects remain under wraps does not serve the public interest.

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[43]See description of Cross Sound Connector project in the section "Two Instructive Transmission Siting Cases," on page E-8.
[44]Utilities express concern that premature identification of a route may result in increased easement costs. In contrast, rumors of a prospective transmission project may adversely affect land values and burden landowners with uncertainty. We suggest putting all the facts on the table and relying on the siting authority (and courts if necessary) to rule expeditiously on the project and its route and to set fair and reasonable easement costs.
[45]Other possible factors include uncertainties regarding cost recovery in a state or how costs would be allocated among states and companies for interstate projects. Local politics may also be a factor.

Solving Existing Aesthetic Problems in Combination with New Transmission Projects

In some cases, a new transmission project can provide the means to resolving a community's existing aesthetic problem. Consider the case of an aging industrial waterfront area that has the potential to be transformed into a civic and tourist center, but its best views are marred by an accumulation of high voltage lines left over from its industrial past. Some communities are working with their utilities on such projects by finding ways to remove some or all of these lines in conjunction with upgrading other transmission lines nearby. This somewhat radical approach—removing still-functional facilities from service for aesthetic reasons—can produce a more efficient transmission system, while strengthening public support for an otherwise intrusive project.

One example is in Minnesota. As part of the controversial Chisago-Apple River proposal, a mediation process revealed the existence of an opportunity to clean up the visual effect of accumulated power lines in the city of Taylor Falls, MN. Power lines would be removed, and one 161 kV line would cross the river in its place. The concept would also place the new line underground for some distance near the waterfront. Execution of this idea is still pending; Xcel and Dairyland Cooperative have not yet filed the new proposal with siting authorities in Minnesota and Wisconsin.

Another example is in Vermont, where the Vermont Electric Power Company and the City of Burlington are working together in advance of a major VELCO transmission siting proposal to see if lines on the redeveloped waterfront of Vermont's largest city can be removed as part of the project. Advance planning ensures that regardless of the decision, all sides will know that great effort was made by VELCO to find positive collateral benefits.

Federal Actions to Improve the Siting Process

There are several ways, described in the subsections below, that the federal government could promote improved transmission siting performance in the United States, independent of how jurisdiction is apportioned between state and federal regulators.

Improving federal land management agency reviews

Probably the second-most-often-heard category of complaints about the transmission siting process (after concerns about the state process) relates to federal land management agency reviews of proposals. Almost 29 percent of the total land area of the United States is owned by the federal government and managed by the Departments of Defense, Agriculture, Interior, and other agencies (*Statistical Abstract of the United States, 2000;* see box below for additional details). In addition, other non-federal land areas such as airsheds, wetlands, navigable waterways, and coastal zones are subject to federal oversight by the Environmental Protection Agency, the Corps of Engineers and other agencies.

These complaints fall into four general categories:

- There is often inconsistency within an agency in the ways local or regional land managers review transmission projects.

Distribution of Federal Lands in the United States

Although almost 29 percent of the land area of the United States is federally owned, the distribution of this land is very uneven. Nearly 38 percent of all federal land is in Alaska where almost 68 percent of the state is federally owned. Another 54 percent of all federal land is concentrated in the 11 states of the contiguous U.S. that are located wholly or partially west of the Continental Divide. Additional details about these 11 states are presented in the following table:

State	Total Area (Acres, in 000's)	% Federal Land
Arizona	72,688	45.6
California	100,207	44.9
Colorado	66,486	36.4
Idaho	52,933	62.5
Montana	93,271	28.0
New Mexico	77,766	34.2
Nevada	70,264	83.1
Oregon	61,599	52.6
Utah	52,697	64.5
Washington	42,694	28.5
Wyoming	62,343	49.9

Source: *Statistical Abstract of the United States, 2000* (U.S. Dept. of Commerce, December, 2000), Table No. 381 (1997 data).

- When two (or more) federal agencies are involved, there is frequently inadequate communication and coordination between them.
- Review of transmission proposals does not appear to be important in comparison to the primary mission of the agency.
- Federal agencies frequently wait to conduct their reviews until state reviews are completed and a final route has been selected. This introduces the risk that a federal agency may require a route change, leading to another (time- and cost-consuming) iteration in the state process.

(See box on Alturas case (next page), which illustrates some of these problems.) It should be noted that research for this paper also found reports of good cooperation between states and federal agencies.

The Alturas 345 kV Intertie Project

This project demonstrates some reasons why potential developers of transmission facilities regard gaining permits from affected federal agencies as one of the most difficult and frustrating aspects of transmission siting.

The Alturas line is 163 miles long and runs between Reno, Nevada, and Alturas, California. About 20 miles of the line is in Nevada and the balance is in northern California. The line was needed primarily to support reliability in the fast-growing area around Reno, and to enable the applicant, Sierra Pacific, to gain access to low-cost hydro from the Pacific Northwest for the benefit of retail customers in both Nevada and California.

The project was proposed to the Nevada Public Service Commission early in 1993 and the Commission approved it in November 1993. Sierra Pacific then turned to the other affected agencies: the California Public Utilities Commission (CPUC), and several federal agencies [the Bureau of Land Management (BLM), the U.S. Forest Service, the Bonneville Power Administration (BPA), and the U.S. Fish and Wildlife Service (FWS)]. BLM became as the lead federal agency for the purposes of preparing an environmental impact statement because it had the most affected acreage. The Forest Service had two affected areas, three line miles in the Modoc National Forest in California, and eight line miles in the Humboldt-Toiyabe National Forest in Nevada. The California Public Utilities Commission became the lead agency for state environmental purposes.

In the spring of 1994 BLM and CPUC jointly hired a consulting firm to prepare an environmental impact report (EIR) for the state and an environmental impact statement (EIS) for the federal agencies. The applicant paid the cost of this work. The draft statements were issued for comment in March 1995. In the fall of 1995, the applicant believed that the comments received could be satisfactorily addressed through several kinds of mitigating measures. BLM issued the final EIS in November 1995, and approved its portion of the project in February 1996. The CPUC approved its portion of the line in January of 1996. However, in February 1996 the manager of the Humboldt-Toiyabe National Forest issued a "no action" decision, and argued that the EIS had been flawed because it had not addressed a sufficiently wide range of alternatives, including the alternative of skirting the Humboldt-Toiyabe National Forest entirely.

The applicant appealed this decision, first to the regional forest manager and then to the deputy chief of the Forest Service. The appeal process took several months, and the results of the appeal were inconclusive. In June 1996 the deputy chief ordered the "no action" decision withdrawn, but he also directed the Humboldt-Toiyabe manager to obtain whatever information was needed to make a new decision. This led to several months of dialogue between the applicant and the Humboldt-Toiyabe manager, and the filing by the applicant of several hundred pages of additional information. The manager of the Modoc National Forest, who had not issued a final decision on the portion of the route that would cross the Modoc area, joined this dialogue.

However, the applicant found that the continuing uncertainty over the acceptability of the Humboldt-Toiyabe route segment was making it difficult to gain required permits from local governments in Nevada that would be needed for the construction phase of the project. These problems led the applicant to examine the option of an alternative route on private land around the Humboldt-Toiyabe National Forest, even though this had several disadvantages. It would put the line into more developed areas, and make it more visible to local residents. This alternative route was about the same length as the initial route, but it was more costly because it would need more expensive towers in several locations, the right of way was more expensive, and additional legal costs would be involved. At length Sierra Pacific decided to pursue the private-land route and withdrew its application to cross the Humboldt-Toiyabe area in February 1997. Due to these route changes, the applicant had to go through some local-level processes a second time in Nevada.

In April 1997, the manager of the Modoc National Forest issued a decision on the EIS, also denying the applicant's request for a permit. Sierra Pacific appealed this decision to the chief of the Forest Service in May 1997, and this led eventually to the issuance of a permit in October 1997. However, several other parties to the proceeding appealed this latter action. After review, the decision to issue the permit was upheld in January 1998.

Construction of the project was begun in February 1998 and completed in December 1998. The applicant estimates that the difficulties with the Forest Service delayed the project by at least two years and led to additional costs of well over $20 million.

Addressing these concerns about federal agency reviews must start with a recognition that a change in priorities is required: applicants deserve a timely, consistent, and substantive response from the federal government. For the same reason that a "one-stop" siting process makes sense at the state and local level, federal agencies should find a way to participate cooperatively and constructively in the overall siting process. This may require additional effort and resources from both the applicant and the agencies to consider alternative routes and solutions earlier in the process.

One option is to centralize individual agency responses to transmission proposals.[46] Special staff groups could be created in the headquarters of appropriate federal agencies to work jointly on reviewing transmission proposals, particularly if efforts to improve coordination among federal agencies and to train and inform regional managers about the importance of the transmission grid do not achieve the desired results.

Another option is to designate a lead agency for cases where two or more federal agencies are affected, and give that agency jurisdiction over all federal matters affected by the transmission proposal. It would be difficult to gain broad support for this approach because it would require some federal agencies at times give jurisdiction to another federal agency regarding land use within their domains. It is worth noting that this approach is not used in siting natural gas pipelines, even though siting such lines is wholly under federal jurisdiction.

A less radical version of this option would be to make the FERC the lead agency for coordinating all federal reviews of proposed transmission facilities, while specifying that other affected federal agencies would participate in the reviews as cooperating agencies, and would retain their existing authorities. Charging one agency with overall coordination of the process, especially one already experienced with environmental and other

[46]See comments to the DOE by the Electricity Consumers Alliance, discussed in the section "Improving the Existing State-Based Siting Process" on page E-45.

types of analysis of electricity projects, would help to bring greater consistency and predictability to the federal review process. Further, given FERC's other responsibilities in the electricity area, it would have stronger reasons than most other agencies to press for good coordination, and eventually it would also have regional transmission plans at its disposal to use in confirming whether a proposed transmission line is needed. Presumably, establishing this approach would require federal legislation because of FERC's status as an independent regulatory agency.

Other measures that do not interfere with agencies' jurisdiction could be considered, such as memoranda of understanding and other commitments to complete project reviews in a timely way. A standard form or protocol could be developed to ensure that cooperative understandings are in place without compromising any agency's authority.

Innovative siting practices

Not surprisingly, most applicants prefer to use siting practices that have worked before. They believe this approach improves their chances of success, and that new approaches are risky. One reason for their caution is that mounting a transmission siting effort can be expensive, particularly if it is unsuccessful.[47] Despite this bias, innovative approaches that invest in early and more open planning and consider a more comprehensive range of alternatives may produce better outcomes. DOE should consider funding demonstration programs in this area.

Increasing transmission capacity of existing facilities

It is increasingly well understood that for some types of transmission system needs, adding generation resources in the load center can increase transfer capacity. In addition, new technologies such as static var compensators can give operators more control over grid flows and lead to a reduction in the amount of capacity that must be reserved for "N-1" contingencies.[48] DOE could focus resources on demonstrating technological options that are available but not in common practice, such as FACTS, high-voltage direct current (HVDC), and high-temperature superconductivity (HTS), which would increase the transfer capacity of existing facilities.[49]

Identifying "best practices" for reviewing agencies

DOE could work with appropriate state-based organizations[50] to identify "best practices" for consideration by transmission siting authorities. The topics to be addressed could include:

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[47]See the section "Description of the Transmission Siting Process," on page E-3, for details on a transmission project that Florida Power abandoned after more than a decade of effort and expenditures of $23 million.

[48]An N-1 Contingency refers to the practice of assuring that the transmission system can withstand the change in power flows resulting from the sudden loss of any element on the system.

[49]FACTS devices are sophisticated solid-state electronic switches that allow operators to control flow on certain power lines. HVDC lines do not operate synchronously with the AC grid but can move large amounts of power over great distances with almost no losses. HTS can also move large amounts of power with almost no losses; this technology is under development. See Issue Paper *Advanced Transmission Technologies* by J. Hauer, T. Overbye, J. Dagle, and S. Widergren.

[50]Participation by organizations such as the National Governors' Association, the Western Governors' Association, and the National Association of Regulatory Utility Commissioners would be important to the success of such a project.

- Open planning;
- Treatment of alternatives;
- Criteria for project approval, including determination of need;
- Maximum time limits;
- Strategic use of undergrounding;
- Innovative easement agreements;
- Use of mitigating measures;
- Estimating probable cost/benefit implications for affected jurisdictions; and
- Development of model rules and decision criteria.

The Tennessee Valley Authority and the federal power marketing administrations with active transmission siting responsibilities could also participate in this project and adopt the resulting practices.

Guidelines for applicants

The federal government has a great capacity to provide leadership as can be seen in many energy-related areas. For example, the Federal Energy Management Program of DOE is working to make federal buildings energy efficient, not only as good management practices for those buildings, but also to set an example. Regarding transmission siting, DOE could work with state agencies[51] and industry organizations[52] to develop guidelines that would aid applicants in securing timely approval for proposed new transmission or grid-related projects. This project to develop guidelines would consider much the same subject matter as the preceding one focused on "best practices" but from the applicant's perspective. The Tennessee Valley Authority and the federal power marketing administrations with active transmission siting responsibilities could also contribute to the success of this project.

Innovative regulatory methods

Investor-owned utilities' high-voltage transmission systems are under FERC's rate-making jurisdiction.[53] Many utilities believe that rate-making incentives to build new transmission facilities are not adequate and have proposed increasing the return on investment allowed in transmission rates. There is also concern that transmission pricing should better reflect system economics and power flows. Addressing these proposals in detail is outside the scope of this paper,[54] but some comments about alternative approaches are relevant in the context of improving siting processes.

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[51]See previous footnote.
[52]Organizations such as the Edison Electric Institute, the American Public Power Association, the National Rural Electric Cooperative Association, and the Electric Power Supply Association could provide valuable assistance in the design and implementation of such a project.
[53]This is true everywhere in the contiguous United States except Texas.
[54]See the Issue Paper *Alternative Business Models for Transmission Investment and Operation* by S. Oren, G. Gross, and F. Alvardo addresses the return on equity issue. Generally, performance-based rate making for transmission service offers the prospect of improving utility incentives by bringing them into better alignment with the public interest.

Utilities' incentives are clearly driven by the regulations that define their revenue stream. Volumetric transmission rates promote increased volume on the grid, and utilities respond in a logical way by increasing throughput on their systems. In some cases, congestion or reliability problems ensue, leading to calls for additional capacity. An alternative approach would be to compensate utilities fairly (at whatever rate of return on equity regulators choose) for the use of their facilities regardless of throughput. Each utility would have its transmission rates set to recover its costs plus the return and would be subject to periodic rate adjustments to true up any divergence between expected revenue and actual results. Performance incentives for reliability and service could be incorporated into the system.

Under this regulatory alternative, a transmission-owning utility has no undue bias toward growth in assets. Investments that may promote more efficient use of existing facilities and avoid the need for new facilities may be more vigorously pursued, which may align corporate incentives more closely with the public interest. FERC could actively invite utilities to experiment with this form of regulation for a defined period of time. DOE could work with FERC to develop the plan.

Another area where FERC activities could be very helpful to transmission siting is in RTO development. An RTO can become an unbiased source of accurate, publicly tested regional planning information that can help siting authorities evaluate and validate the need for a variety of grid-related investments. An RTO can also provide insight about the appropriate allocation of the costs of interstate projects and about how transmission services should be priced in order to provide accurate economic signals for grid-related investments.

Summary and Conclusions

Siting electric transmission lines is currently a state responsibility.[55] Each state has the option to address transmission siting in its own laws, and most have done so. In most states, applicants must demonstrate that proposed facilities are needed, and a state siting authority must confirm that construction of the facilities would serve the public interest. If a facility would cross state lines, approval is needed from each state affected. Additional approvals are required from federal agencies if the line would cross federally owned or controlled lands, and consent from Native American tribes is needed to cross tribal lands. The public process for reviewing and approving the siting of proposed transmission facilities is unavoidably difficult and complex because it entails fitting long-lived and highly visible structures into physical surroundings where land is already in use for other purposes. This is especially true for transmission projects that are large in geographic scale because they tend to require approvals from many affected jurisdictions.

During the past decade, most small-scale, intrastate transmission proposals have been approved without major delay or controversy. Delay and controversy have been more common in larger, interstate projects; however, approval has been obtained eventually in most cases if the applicant has been persistent and presented alternative proposals. Some parties believe that this record is misleading, and suggest that some or even many applicants have refrained from proposing large-scale, multistate transmission projects. It is difficult to verify the extent of such withholding, but there has been a striking disparity during the past decade

[55]With the exception of the federal power marketing administrations and the Tennessee Valley Authority, which have their own siting authorities.

between the level of new investment in generation and the level of new investment in transmission. This disparity suggests that some major transmission projects may indeed have been withheld and may not be just the result of excess capacity built in prior decades (though siting authorities should guard against the prospect of accelerated construction producing a new generation of stranded utility costs).

There are several possible reasons for withholding of proposals:

- Regional-scale transmission planning has lagged behind the development of regional-scale bulk power markets. It may be that the economic feasibility of some multistate projects is only now becoming apparent. The penalties to companies or investors who misjudge the economics of such projects can be severe.
- The transmission sector of the industry is in the midst of a fundamental reorganization. Many companies have not known whether they will remain in the transmission business or what the rules will be that will determine the rate of return on new transmission investments. It is reasonable to assume that some companies will not present new proposals until these uncertainties are resolved.
- The present state-based transmission siting process is difficult at best, particularly for large-scale projects.

Given these considerations, it is understandable that there is disagreement between those who think that the existing siting regime is basically sound but needs improvement, and those who believe that fundamental reforms are needed.

Problem Areas in the Existing Regime

Approval of a proposed transmission project is the culmination of a long and complex process that can go awry for many reasons. In addition, the transition to regional bulk power markets may raise significant new difficulties related to transmission siting. Some of the principal problem areas are:

Need for regional-scale transmission planning

Although some regional plans have been developed, many areas of the nation do not have regional plans, and some of the plans that have been prepared are very incomplete (see the Issue Paper *Transmission Planning and the Need for New Capacity* by E. Hirst and B. Kirby). There is an urgent need for regional transmission plans that after public review will confirm to prospective applicants and reviewing agencies that specific regional transmission needs have been identified and ranked according to priority. Regional transmission planning is one of several critical functions that regional transmission organizations (RTOs) would perform, as envisioned by FERC.

Possible need for interim transmission plans

Rather than wait for RTOs to be formed and regional transmission plans to be developed by them, as an interim measure it might be useful for DOE and FERC to identify key bottlenecks and for the FERC to task administrative law judges to work with appropriate parties in the bottleneck areas to develop interim transmission plans. A possible benefit of such plans is that they would probably flag some important issues affecting groups of states, and thus help to spur the formation of cooperative regional institutions.

Need for transparent planning and systematic consideration of alternatives by applicants

To win approval, a transmission proposal should be developed through a process open to participation by all interested parties and with systematic attention to a broad range of alternatives.

Need for coordination, consistency, and timeliness of federal agency reviews

Applicants and other parties cite four kinds of problems with federal agency reviews of transmission siting proposals:

1. Local or regional officials within an agency are sometimes inconsistent in their reviews of transmission projects.
2. If two or more federal agencies are reviewing a project, communication and coordination between/among them are sometimes inadequate.
3. Review of transmission proposals is sometimes given little priority in comparison to the primary mission of the agency.
4. Federal agencies sometimes wait to conduct their reviews until state reviews are completed and a final route has been proposed. This introduces the risk that a federal agency may require a route change, leading to another time- and cost-consuming iteration in the state-level process.

Need for coordination and development of a common review process

All state agencies with review responsibilities, relevant federal agencies, and tribal authorities within a region should use a common review process and coordinate reviews of transmission siting proposals. Inadequate coordination and cooperation among reviewing agencies (and the applicant) can significantly hinder the siting process and may lead to rejection of a project by one or more agencies.[56]

Need to regulate the time allowed for reviews

Many corporate parties to the transmission siting process assert that the unpredictable timing of typical state-based siting processes contributes significantly to the uncertainty hindering key business decisions in the transmission sector today. Many parties favor state and/or federal legislation setting fixed time limits (e.g., 12–18 months) for reviews. Projects not acted upon within the time period would be approved by default. The success of this approach would depend to a significant extent on the filing of a complete application at the outset, and affected agencies would probably enforce "completeness" very strictly.

[56]Examples include AEP's 765-kV line in Virginia and West Virginia, and the Cross Sound Connector project between Long Island, New York, and Connecticut, both of which are described above in the section "Assessment of Current Siting Regime."

Potential disagreement between states over definition of "need"

One state's definition of “need” for new transmission capacity may include transmission to enable additional electricity commerce; a neighboring state may limit "need" to transmission needed to maintain reliability.

Potential disagreement between states over whether a particular facility is needed

Even if two states have identical definitions of need, they may still not agree that a proposed facility is the best alternative for meeting a specific requirement.

Potential disagreement between states over distribution of costs and benefits

An interstate project may fail to win all required approvals unless the affected states come to agreement about the distribution of the facility's costs and benefits. A key element of disagreement may be the time horizon over which benefits and costs are assessed.

Need for regional institutions to facilitate the siting process for interstate projects

The western states have had extensive experience with siting interstate transmission projects, and an institutional framework is evolving under the auspices of the Western Governors' Association[57] to aid the states in dealing with such projects. In the eastern U.S., however, interstate projects have been less frequent, and, for the most part, comparable institutional frameworks remain to be developed.

Options for Improving the Transmission Siting Process

The recent debate over whether to make a federal agency, most likely FERC, responsible to some degree for siting major new transmission facilities has been healthy and useful though sometimes acrimonious. It has put all parties on notice that this process must work—it must lead to a timely determination by appropriate government agencies regarding whether proposed facilities are needed and to the approval of routes or sites for needed facilities. The debate has also provided impetus for a searching examination of options for improving the process. Many of these options are listed below.

Options for individual states

1. Promote or require an open, transparent transmission planning process.
2. Require project applications to address a broad range of alternatives.
3. Review and if appropriate clarify or update criteria for approval; consider whether the requirements of commerce should be recognized explicitly in determining “need” for transmission capacity.

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[57] The Western Interstate Energy Board, which is the energy arm of the Western Governors’ Association, and the Western Conference of Public Service Commissions acted jointly in 1984 to create the Committee on Regional Electric Power Cooperation (CREPC). CREPC has representation from the regulatory commissions, energy agencies, and facility-siting agencies in the 11 states and two Canadian provinces in the Western Interconnection. Through CREPC, the western states have begun negotiations to establish a common interstate transmission-siting protocol.

4. If necessary, modify state law to enable siting authorities to take account of out-of-state benefits when assessing the merits of a transmission siting proposal.

5. Adopt a "one-stop" siting process. Local and county governments could use zoning to direct utility facilities to preferred locations, but they would lose the ability to reject a project. State reviews would be consolidated in the siting authority.

6. Set a maximum time limit (e.g., 12 or 18 months) for reviews by state or local agencies.

7. State clearly what materials must be included in an application, and refuse to initiate a review until an application is complete.

8. Promote use by applicants of both deterministic and probabilistic planning methods.

9. Promote more consistent use of "rolled-in"" and "cost causation" approaches to recovering the cost of new grid-related investments, to minimize either favoring or disadvantaging particular technological alternatives.

10. Promote innovative approaches to meeting transmission grid needs.

11. Emphasize to prospective applicants that undue minimization of transmission project costs can be self-defeating.

Regional options

All of the state-level options listed above have regional significance; that is, if they were considered and applied by all states in a given region, the result would probably be greater regional consistency and efficacy in siting policies and practices. The options below focus on development of regional institutions that could, among other objectives, promote such consistency and efficacy. States, federal land management agencies, and Native American tribes should consider the following options:

1. Support and participate in open, transparent regional transmission planning.

2. Promote the development of cooperative regional transmission siting institutions that would have two key missions:

    (a) Develop elements of a common siting process, usable by most and if possible all reviewing agencies; and

    (b) Maintain parallel processes among reviewing agencies, utilizing consistent information, identifying information gaps or possible points of disagreement early, and ensuring that these are addressed by a scheduled calendar date.

3. Agree that if an agency fails to complete its review by a scheduled calendar date, the application is approved by default.

4. Consider whether a regional organization with decision-making powers should be estab-

lished to address some energy regulatory matters on a regional basis (i.e., oversight of system planning, siting and permitting, rate regulation, or other matters).

Federal options

Most of the options listed above could be aided through specific federal actions, including:

1. Establish broad federal support for open, transparent regional-scale planning to address generation requirements, generation siting considerations, transmission requirements, and related issues.

2. As an interim measure while waiting for RTOs to be formed and regional transmission plans to be prepared by them, DOE and FERC could act jointly to identify key transmission bottlenecks, and FERC could task administrative law judges to work with appropriate parties in each bottleneck area to prepare an interim transmission plan by a specific date.

3. Improve the process for the review of transmission siting proposals by federal land management agencies. Several sub-options could be implemented by a Presidential executive order:

    (a) Direct federal land managers and other relevant agencies to support and participate in common and coordinated state or regional processes for timely review of proposals for new transmission facilities requiring federal approval.

    (b) Require all federal reviews to be completed within 18 months after the filing of a complete application. Applications not acted upon within 18 months would be approved by default.

    (c) Establish training programs on the national significance of the transmission grids and related issues, and make these programs mandatory for federal officials authorized to approve or reject transmission siting proposals.

    (d) Create special staff groups in the headquarters of appropriate federal agencies to work jointly to prepare consolidated, multi-agency reviews of proposed transmission projects.

    (e) Direct that if two or more agencies have jurisdiction over a proposed transmission project, the Office of Management and Budget shall designate one of them as the lead agency, responsible for coordinating the preparation of a timely joint review of the proposal. (Note: An alternative to this arrangement would be to enact federal legislation making FERC responsible for coordination of all federal reviews of transmission projects, as described below.)

4. Seek federal legislation that would:

    (a) Direct the Secretary (DOE) or FERC to initiate a rulemaking to establish criteria for the identification of transmission bottlenecks (or projects to ease such bottlenecks) of national or regional importance.

(b) Affirm that for projects designated to be of national or regional importance, an applicant would have the right to petition FERC to assume a backstop role in the event that a state or tribal reviewing agency does not act to approve or deny the project within 18 months after the filing of a complete application. (A stronger but more controversial and less predictable formulation would be to empower applicants to petition FERC when a state, tribal, or federal reviewing agency acts in the allotted time but rejects the application. "Forum shopping" could become a significant problem if applicants could always turn to FERC for a second opinion. If this version were adopted, items c and d below would have to be modified for consistency.)

(c) Empower FERC to decline a petition for cause, and limit FERC's role to serving as a backstop for the agency that has not acted, without affecting the actions or responsibilities of other reviewing agencies.

(d) Direct that FERC shall be the lead agency for coordinating all reviews of proposed transmission facilities by federal agencies, that other affected federal agencies shall participate as cooperating agencies, and that the cooperating agencies will retain their existing authorities with respect to the issuance of permits for lines crossing lands under their jurisdiction.

5 Undertake a DOE project, jointly with NGA, WGA, NARUC, and other appropriate state-based organizations to articulate a set of "best practices" related to transmission siting for consideration by all states.

6. Undertake a DOE project, jointly with appropriate state agency organizations and industry trade associations, to articulate a set of guidelines for applicants, designed to increase the likelihood of approval of proposed new transmission or grid-related projects.

7. Undertake a DOE demonstration program to support applicants in taking innovative approaches to transmission siting proposals (e.g., treatment of alternatives, use of innovative or little-used technologies, imaginative use of mitigating measures, etc.).

8. Undertake a DOE demonstration program to support the use of new or under-used methods and technologies for increasing the transmission capacity of existing facilities.

9. Support FERC efforts to improve the incentives of transmission-owning companies and other potential developers of new transmission capacity or other grid-related projects through performance-based regulation.

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Advanced Transmission Technologies

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Introduction

This paper discusses the use of advanced technologies to enhance performance of the national transmission grid (NTG). We address present and developing technologies that have great potential for improving specific aspects of NTG performance, strategic impediments to the practical use of these technologies, and ways to overcome these impediments in the near term.

Research and development (R&D) infrastructure serving power transmission is as badly stressed as the grid itself, for many of the same reasons. The needs are immediate, and the immediate alternatives are few. Timely and strategically effective technology reinforcements to the NTG need direct, proactive federal involvement to catalyze planning and execution. Longer-term adjustments to the R&D infrastructure may also be needed, in part energy policy can evolve as the NTG evolves.

Technology and a coordinated national effort are only two of the elements necessary for timely resolution of the problems facing the national energy system. Sustainable solutions require careful balancing between generation and transmission, profit and risk, the roles of public and private institutions, and market forces and the public interest. There is a vast body of information and opinion on these issues. A recent white paper by EPRI (formerly known as the Electric Power Research Institute) clearly lays out the broad issues and a comprehensive inventory of technology options for enhancing the grid, including detailed assessments of their direct costs and benefits. Titled "The Western States Power Crisis: Imperatives and Opportunities," (EPRI 2001), this document notes that "…the present power crisis—most evident in the Western states but potentially a national problem—requires a fundamental reassessment of the critical interactive role of technology and policy in both infrastructure and markets" (EPRI 2001). Similar assessments of needs and solutions, many of which arrive at similar conclusions, are found in a series of studies extending back to 1980 (DOE 1980). A widely shared view concerning the urgency of technology solutions is provided in Scherer 1999.

The strategic need is not just for new technology in the laboratory but for an infusion of improved, cost-effective technology to work in the power system. The chief impediments to infusion are institutional and can be resolved by a proactive national consensus regarding institutional roles. Until this consensus is achieved, the lack of cohesion between technology and policy may be disruptive for continued development of the NTG and the infrastructures that it serves.

This issue paper discusses the use of new technologies to enhance the performance of the NTG, as follows:

- Background on power system operation in general and the specifics of the NTG.
- The new demands being placed on the NTG and outlines the technology needed to address these demands.
- The impact of existing institutional frameworks on the application of new technology to the transmission grid.
- The strategic challenges that can be addressed through accelerated use of selected new technologies.
- The institutional issues associated with moving new technology from the research laboratory to deployment in the grid.
- A summary of some of the options discussed in the paper.
- Appendix A is an extensive (though not exhaustive) list of new technologies that could be applied to the NTG.

Background

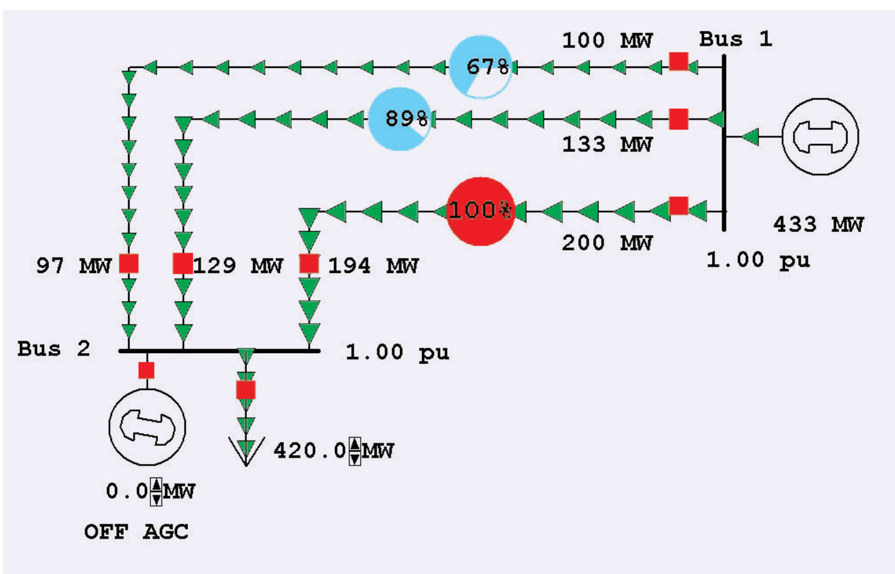
The transition to open electrical energy markets is stressing the NTG beyond its design capabilities. Less conspicuously, this transition is also stressing the management infrastructure by which transmission facilities are planned, developed, and operated. Stresses on this infrastructure are a major strategic impediment to the focused development and timely deployment of technical solutions to shortfalls in national grid capacity. The subsections below give some transmission system background that is necessary to understand these technological issues.

Power System Components and Reciprocal Impacts

The power system has three components: generation, load, and transmission. Electric power is produced by generators, consumed by loads, and transmitted from generators to loads by the transmission system. Typically, the "transmission system" (or "the grid") refers to the high-voltage, networked system of transmission lines and transformers. The lower-voltage, radial lines and transformers that actually serve load are referred to as the "distribution system." The voltage difference between the transmission system and the distribution system varies from utility to utility; 100 kV is a typical value. This paper focuses only on advanced technologies for the transmission system.

It is important to understand reciprocal impacts among the transmission system, load, and generation. Because the transmission system's job is to move electric power from generation to load, any technologies that change or redistribute generation and/or load will have a direct impact on the transmission system. This can be illustrated using a simple two-bus, two-generator example shown in one-line form in Figure 1. The solid lines represent the buses, the circles represent the generators, and the large arrow represents the aggregate load at bus 2. Three transmission lines join the generator at bus 1 to the load and generation at bus 2. Superimposed on the transmission lines are arrows whose sizes are proportional to the flow of power on the lines. The pie charts for each line indicate the relation between the loading on each line and its rated capacity. The upper and middle transmission lines have a rating of 150 MVA, and the lower line has a rating of 200 MVA. In addition, we assume that the bus 1 generation is more economical than the generation at bus 2, and the entire load is being supplied remotely from the bus 1 generator. With a bus 2 load of 420 MW, the power distributes among the three lines based on their impedances (which are not identical), so the upper line is loaded at 67 percent, the middle at 89 percent, and the lower at 100 percent. Note: there are 13 MW of transmission line losses in this case.

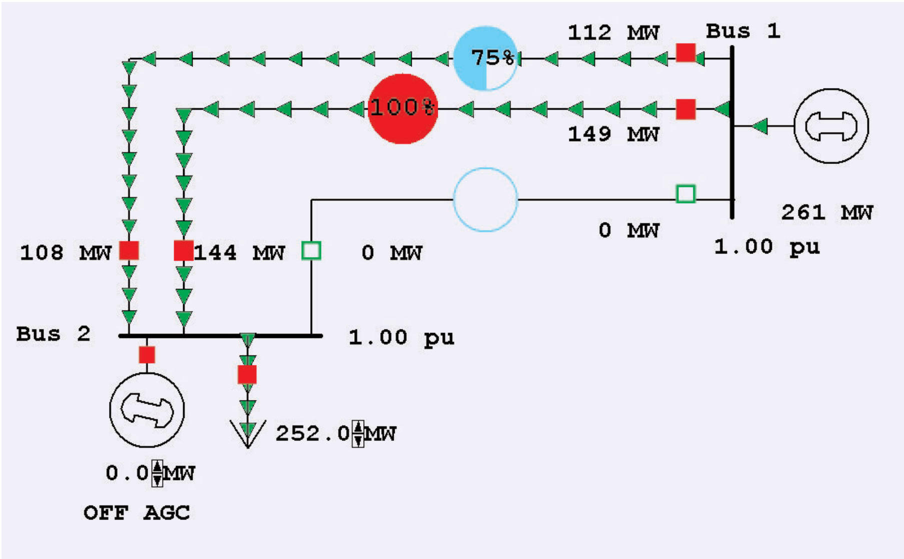
Figure 1: Two-Bus Example with No Local Generation



Transfer Capacity

A natural question to ask is: what is the transfer capacity of the transmission system described in Figure 1? That is, how much power can be transferred from bus 1 to bus 2? The answer is far from straightforward. At first glance, the transfer capacity appears to be 420 MW because this amount of power causes the first line to reach its limit. However, this answer is based on the assumption that all lines are in service. As defined by the North American Electric Reliability Council (NERC), transfer capacity includes consideration of reliability. A typical reliability criterion is that a system be able to withstand the unexpected outage of any single system element; this is known as the first contingency total transfer capability (FCTTC). Based on this criterion, Figure 2 shows the limiting case with an assumed contingency on the lower line, which results in a transfer capability of only 252 MW. Which number is correct?

Figure 2: Two-Bus Example with Limiting Contingency



The answer depends on system operational philosophy and on the availability of high-speed system controls. If the operational philosophy requires that no load be involuntarily lost following any individual contingency, and if there are no mechanisms to quickly increase the generation at bus 2, voluntarily decrease the load at bus 2, or redistribute the flow between the remaining upper two lines, then the limit would be 252 MW. With these limitations, the only way to increase the transfer capacity would be to construct new lines.

However, if we relax one or more of these conditions, the transfer capacity could be increased without construction of new lines. For example, one approach would be to provide at least some of the bus 2 load with incentives so that, following the contingency, some customers on bus 2 would voluntarily curtail their loads. Incentives might involve price-feedback mechanisms or agreements to allow the system operator to curtail load through some type of direct-control load management or interruptible demand. Another approach would be to have a mechanism for quickly committing some local bus 2 generation. Availability of local generation reduces the net loading on the transmission system and can increase its capacity. A third approach would be to use advanced power electronics controls such as flexible AC transmission system (FACTS) devices to balance the load between the upper two lines.

The unifying themes of these alternative approaches are knowledge about the real-time operation of the system, availability of effective controls, and an information infrastructure that permits effective use of the controls. To understand these themes, it is important to understand the complexity of the actual national transmission grid.

Complexity of the National Transmission Grid

The term "national transmission grid" is something of a misnomer. The North American transmission grid actually consists of four large grids, each primarily a synchronous alternating current (AC) system. Together, these four grids span parts of three sovereign countries (U.S., Canada, and Mexico). By far the largest grid is the Eastern Interconnection, which supplies power to most of the U.S. east of the Rocky Mountains as well as to all the Canadian provinces except British Columbia, Alberta, and Quebec. The Western Interconnection supplies most of the U.S. west of the Rockies, as well as British Columbia, Alberta, and a portion of Baja, California. The remaining two grids are the Electric Reliability Council of Texas (ERCOT), which covers most of Texas, and the province of Quebec. In contrast to the two-bus example presented above, the Eastern and the Western Interconnections contain tens of thousands of high-voltage buses and many thousands of individual generators and loads. Because the individual grids are asynchronous with one another, no power can be transferred among them except in small amounts through a few back-to-back direct current (DC) links. Several major DC transmission lines are also used within the individual grids for long-distance power transfer.

At any given time the loading on the grid depends on where power is being generated and consumed. Load is controlled by millions of individual customers, so it varies continuously. Because electricity cannot be readily stored, generation must also vary continuously to track load changes. In addition, the impedances of the many thousands of individual transmission lines and transformers dictate grid loading. With several notable exceptions, there is no way to directly control this flow—electrons flow as dictated by the laws of physics. Because electricity propagates through the network very rapidly, power can be transferred almost instantaneously (within seconds) from one end of the grid to the other. In general, this interconnectivity makes grid operations robust and reliable. However, it also has a detrimental effect if the grid fails; failures in one location can quickly affect the entire system in complex and dramatic ways, and large-scale blackouts may result.

The grid's ability to transfer power is restricted by thermal flow limits on individual transmission lines and transformers; minimum and maximum limits on acceptable bus-voltage magnitudes; and region-wide transient, oscillatory, and voltage-stability limitations. Given NERC's reliability requirements, these limits must be considered not only for current and actual system operating point but also for a large number of statistically likely contingent conditions as well. The complexity of maximizing the power transfer capability of the grid while avoiding stressing it to the point of collapse cannot be overstated.

Technologies to Increase Transfer Capacity

The goal of this issue paper is to examine technologies that can be used to increase the grid's power-transfer capability. This increase can be achieved by a combination of direct technical reinforcements to the grid itself along with indirect information and control reinforcements that improve grid management practices and infrastructure.

Direct reinforcement of the grid includes new construction and broad use of improved hardware technology. Strategic decisions regarding these two types of improvements are a function of grid management—planning, development, and operation. Grid management involves recognizing transmission needs, assessing options for meeting those needs, and balancing new transmission assets and new operating methods. Timely development and deployment of requisite technology are essential to reinforcing the grid. Requisite technology may not mean new technology. There is a massive backlog of prototype technology that can, given means and incentives, be adapted to power system applications.

Indirect grid reinforcement includes improving grid management by means of technology. Historically, the transmission system was operated with very little real-time information about its state. During the past few decades, advances in computer and communication technology in general and SCADA (supervisory control and data acquisition) and EMS (energy management system) technology in particular have greatly improved data capabilities. Significant real-time data are now available in almost every control center, and many centers can conduct advanced on-line grid analysis. Despite these improvements, more can and should be done. In the control center, additional data need to be collected, better algorithms need to be developed for determining system operational limits, and better visualization methods are needed to present this information to operators. Beyond the control center, additional system information needs to be presented to all market participants so that they can make better-informed decisions about generation, load, and transmission system investments.

Institutional Issues that Affect Technology Deployment

In order to effectively discuss the role of advanced transmission technologies, we have to consider how their deployment is either hindered or encouraged by institutional issues. Ultimately, the bottom line is economics—technologies that are viewed as cost effective will be used, and those that are considered too costly will not. The issue of cost is not simple; public policy must address how costs and benefits should be allocated. For example, it is difficult to beat the economics of traditional overhead transmission lines for bulk power transfer. The lines are cheap to build and entail relatively few ongoing expenses. But the siting of new transmission lines is not so simple; right of way may be difficult to obtain, and new lines may face significant public opposition for a variety of reasons from aesthetic to environmental (for a detailed discussion, see Issue Paper *Transmission Siting and Permitting* by D. Mayer and R. Sedano.) Advanced technologies can reinforce the grid, minimizing the need for new overhead lines, but usually at higher cost than would be paid to build overhead lines. The challenge is to provide incentives that will encourage the desired transmission investments.

Unfortunately, in recent years the uncertainties associated with electricity industry restructuring have hampered progress in transmission reinforcement. The boundaries between responsibilities for operation and planning were once clearly delineated, but these responsibilities are now shifting to restructured or entirely new transmission organizations. This process is far from complete and has greatly weakened the essential dialogue between technology developers and users. Development of new technology must be closely linked to its actual deployment for operational use. Together, these activities should reflect, serve, and keep pace with the evolving infrastructure needs of transmission organizations. The current uncertainty discourages this cohesiveness.

The details and the needs of the evolving infrastructure for grid management are unclear, and all parties are understandably averse to investments that may not be promptly and directly beneficial. Some utilities are concerned that transmission investments may be of greater benefit to their competitors than to themselves. In the near term, relief of congestion may actually harm their businesses. As a result of such forces, many promising technologies are stranded at various points in route from concept to practical use. Included are large-scale devices for routing power flow on the grid, advanced information systems to observe and assess grid behavior, real-time operating tools for enhanced management of grid assets, and new system planning methods that are robust in relation to the many uncertainties that are present or are emerging in the new power system.

Another important issue is that some technologies that would enable healthy and reliable energy commerce are not perceived as profitable enough to attract the interest of commercial developers. Special means are needed to develop and deploy these technologies for the public good. Involvement by the federal utilities and national laboratories may be necessary for timely progress in this area, as well as a broadening of some activities of EPRI or similar umbrella organizations focused on energy R&D along with development of better mechanisms to spur entrepreneurial innovation.

New Demands on the Transmission Grid

The core objective underlying electricity industry restructuring is to provide consumers with a richer menu of potential energy providers while maintaining reliable delivery. Restructuring envisions the transmission grid as flexible, reliable, and open to all exchanges no matter where the suppliers and consumers of energy are located.

However, neither the existing transmission grid nor its current management infrastructure can fully support such diverse and open exchange. Transactions that are highly desirable from a market standpoint may be quite different from the transactions for which the transmission grid was designed and may stress the limits of safe operation. The risks they pose may not be recognized in time to avert major system emergencies, and, when emergencies occur, they may be of unexpected types that are difficult to manage without loss of customer load.

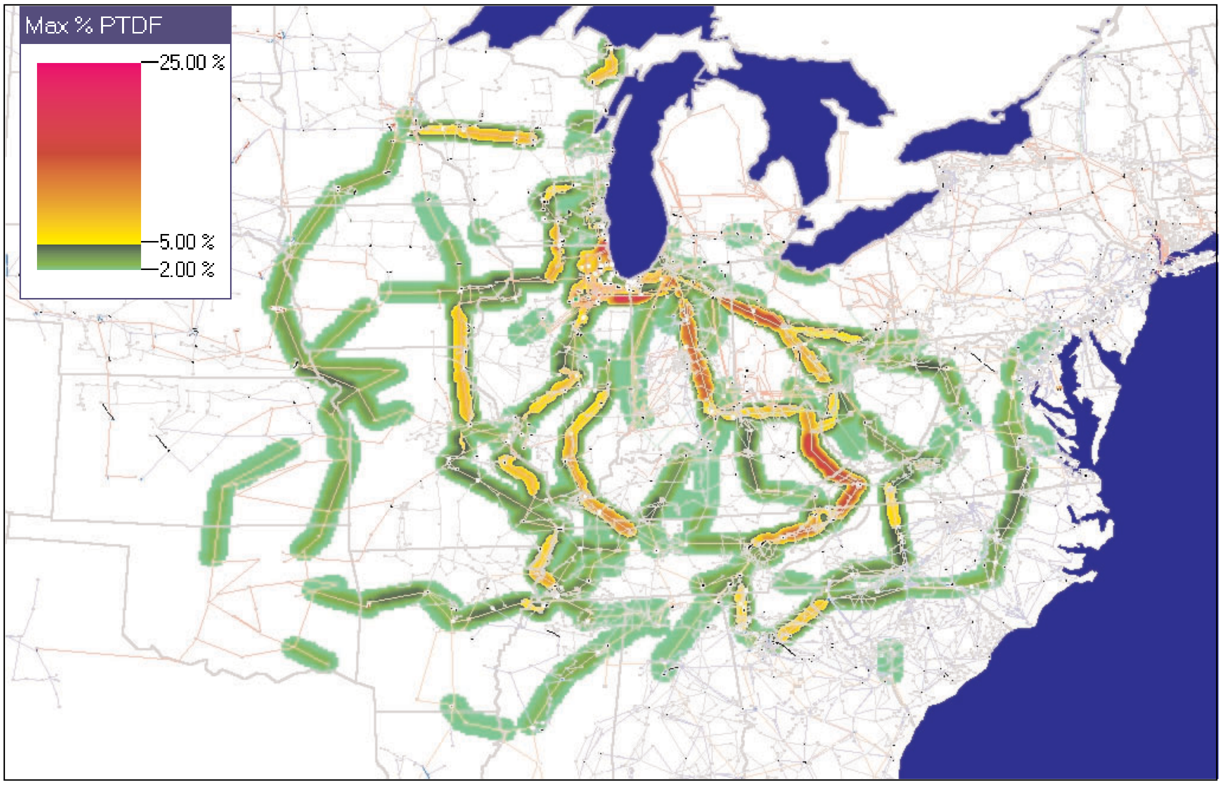
The transmission system was originally constructed to meet the needs of vertically integrated utilities, moving power from a local utility's generation to its customers. Interconnections between utilities were primarily to reduce operating costs and enhance reliability. That is, if a utility unexpectedly lost a generator, it could temporarily rely on its neighboring utilities, reducing the costs associated with having sufficient reserve generation readily available. The grid was not designed to accommodate large, long-distance transfers of electric power.

One of the key problems in managing long-distance power transfers is an effect known as "loop flow." Loop flow arises because of the transmission system's uncontrollable nature. As power moves from seller to buyer, it does not follow any prearranged "contract path." Rather, power spreads (or loops) throughout the network. As an example, Figure 3 shows how a transmission of power from a utility in Wisconsin to the Tennessee Valley Authority (TVA) would affect lines through a large portion of the Eastern Interconnection. A color contour shows the percentage of the transfer that would flow on each line; lines carrying at least two percent of the transfer are contoured. As this figure makes clear, a single transaction can significantly impact the flows on hundreds of different lines.

The problem with loop flow is that, as hundreds or thousands of simultaneous transactions are imposed upon the transmission system, mutual interference develops, producing congestion. Mitigating congestion is technically difficult, and very complex problems emerge when paths are long enough to span several regions that have not had to coordinate such operations in the past. These problems include (but are not limited to) the lack of: effective procedures, operating experience, computer models, and integrated data resources. The sheer volume of data and information concerning system conditions, transactions, and events is overwhelming the existing grid management's technology infrastructure.

Increasing the transfer capacity of the NTG will require combined application of hardware and information technologies. On the hardware side, many technologies can be developed, refined, or simply installed to directly reinforce current transmission capabilities. These technologies range from passive reinforcements (such as new AC lines built on new rights of way or better use of existing AC rights of way by means of

Figure 3: Loop Flow of Power Transfer from Wisconsin to TVA



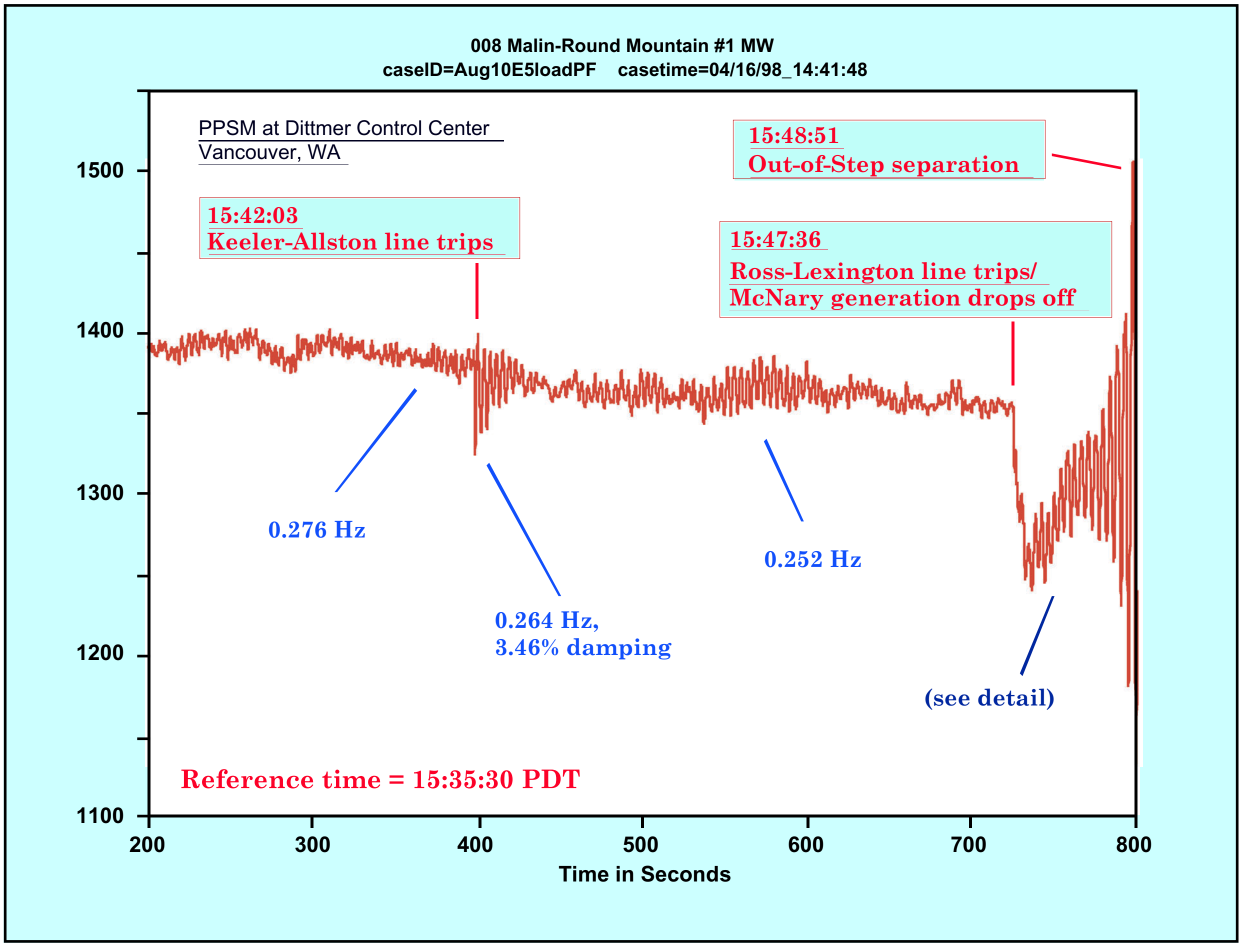
innovative device configurations and materials) to super-conducting equipment to large-scale devices for routing grid power flow. High-voltage direct current (HVDC) and FACTS technologies appear especially attractive for flow control. Effectively deployed and operated, such technologies can be of great value in extending grid capabilities and minimizing the need for construction of new transmission.

The strategic imperative, however, is to develop better information resources for all aspects of grid management—planning, development, and operation. Technologies such as large-scale FACTS generally require the support of a wide-area measurement system (WAMS), which currently exists only as a prototype. Without a WAMS, a FACTS or any major control system technology cannot be adjusted to deliver its full value and, in extreme cases, may interact adversely with other equipment. FACTS technology can provide transmission "muscle" but not necessarily the "intelligence" for applying it.

An example of the information that a WAMS can provide is shown in Figure 4. Review of data collected on the Bonneville Power Administration (BPA) WAMS system following a grid disturbance on August 10, 1996, suggests that the information that system behavior was abnormal and that the power system was unusually vulnerable was buried within the measurements streaming into and stored at the control center. Had better tools been available at the time, this information might have given system operators approximately six minutes' warning of the event that triggered the system breakup (PNNL 1999).

Better information is key to better grid management decisions. The next subsection addresses the kinds of information gaps in current grid management.

Figure 4. Possible warning signs of the Western Systems breakup of August 10, 1996 – an example of information available from WAMS



Information Gaps in Grid Management

As the grid is operated closer to safe limits, knowing exactly where those limits are and how much operating margin remains becomes increasingly important. Both limits and margins must be estimated through computer modeling and combined with operating experience that the models might not and often cannot reflect.

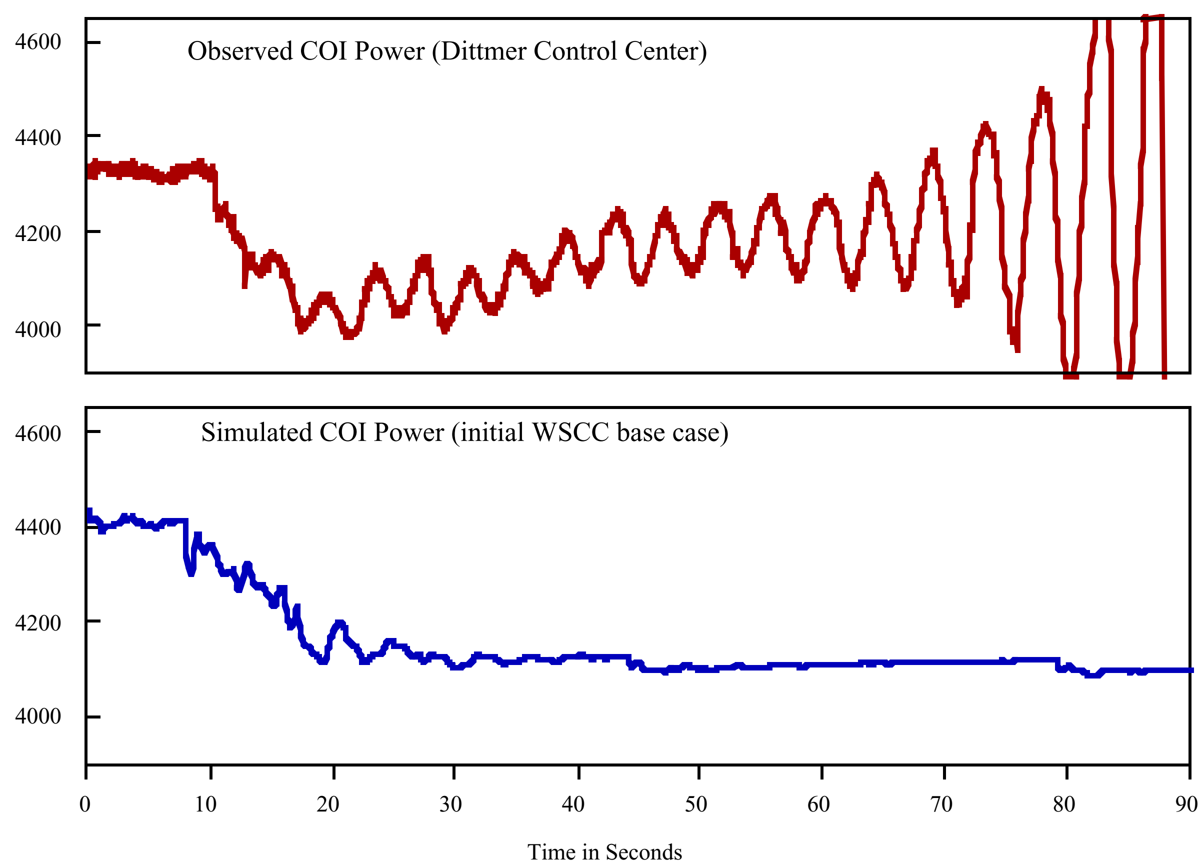
The “edge” of safe operation is defined by numerous aspects of system behavior and is strongly dependent on system operating conditions. Some of these conditions are not well known to system operators, and even those that are known may change abruptly. Important conditions include network loading, operating status and behavior of critical transmission elements, behavior of electrical loads, operating status and behavior of major control systems, and interactions between the grid and the generators connected to it. Full performance of the transmission grid requires that generators provide adequate voltage support plus a variety of dynamic support functions that maintain power quality during normal conditions and assist the system during disturbances.

All of these conditions have become more difficult to anticipate, model, and measure directly. Industry restructuring has exacerbated these difficulties by requiring that transmission facilities be managed with a minimum of information concerning generation assets. To borrow a phrase from EPRI (2001), this is one of many areas where there is a "critical interactive role" between "technology and policy."

Many cases in recent years have revealed that the "edge" of safe grid operation is much closer than planning models had suggested. The Western System breakups of 1996 are especially notable in this respect (see Figure 5), but there have been less conspicuous warnings before and since (PNNL 1999). Uncertainties regarding actual system capability is a known problem of long-standing, and it has counterparts throughout the NTG.

Developing and maintaining realistic models for power system behavior is technically and institutionally difficult, and it requires higher-level planning technology than has previously been available. An infusion of enhanced planning technology—plus knowledgeable staff to mentor its development and use—is necessary to support timely, appropriate, and cost effective responses to system needs. Better planning resources are the key to better operation of existing facilities, to timely anticipation of system problems, and to full realization of the value offered by technology enhancements at all levels of the power system.

Figure 5. Modeling failure for Western System breakup of August 10, 1996. (MW on California-Oregon Interconnection)



Challenges and Opportunities in Network Control

As noted earlier, the existing AC transmission system cannot be directly controlled; electric flow spreads through the network as dictated by the impedance of the system components. For a given set of generator voltages and system loads, the power-flow pattern in an electrical network is determined by network parameters. Control of network parameters in an AC system is usually quite limited, so scheduling of generators is the primary means for adjusting power flow for best use of network capacity. When generator scheduling fails, the only alternative is load control, either through voltage reductions or suspension of service. Load control can be necessary even when some lines are not loaded to full capacity.

A preferred solution would be a higher degree of control over power flow than is currently possible, which would, permit more effective use of transmission resources. Conventional devices for power-flow control include series capacitors to reduce line impedance, phase shifters, and fixed shunt devices that are attached to the ends of a line to adjust voltages. All of these devices employ mechanical switches, which are relatively inexpensive and proven but also slow to operate and vulnerable to wear, which means that it is not desirable to operate them frequently and/or use a wide range of settings; in short, mechanically switched devices are not very flexible controllers. Nonetheless, they are still the primary means used for stepped control of high power flows.

HVDC transmission equipment offers a much greater degree of control. If the support of the surrounding AC system is sufficient, the power flowing on an HVDC line can be controlled accurately and rapidly by means of signals applied to the converter equipment that changes AC power to DC and then back to AC. In special conditions, HVDC control may also be used to modify AC voltages at one or more converters. This flexibility derives from the use of solid-state electronic switches, which are usually thyristors or gate turn-off (GTO) devices.

Although HVDC control can influence overall power flow, it can rarely provide full control of the power flowing on particular AC transmission lines. However, conventional power-flow controllers that are upgraded to use electronic rather than mechanical switches can achieve this control. This upgrade opens the way to a broad and growing class of new controller technology known as FACTS. Many engineers regard HVDC technology as a subset of FACTS technology.

Increasingly, load itself is becoming a fast-acting transmission control device. Some degree of load control has been available for decades through interruptible rates, time-of-day rates, and demand-side management programs. A new possibility is use of real-time price feedback to loads in order to rapidly tailor the flow of power on the transmission grid, perhaps encouraging demand in one location while inhibiting it elsewhere. Advances in communication that can rapidly convey changing electricity prices to industrial and commercial users facilitate this control.

Short-term energy storage can aid in power flow control. Recent work shows that even a small amount of storage can significantly enhance the performance of some FACTS devices, and past research has shown that controllable storage devices have many applications in control of power quality and system dynamics (De Steese and Dagle 1997). These applications are addressed in later sections of this paper.

It should be noted that FACTS technology is still not entirely mature even though it is based on concepts that are two decades old. As has been the case with several other promising technologies, FACTS has not been utilized by the electricity industry at the rate that its apparent technical merits would justify. A number of lessons can be drawn from this. One is that innovative technologies compete against technologies that are already in place and are better understood. Many utilities view FACTS as not cost effective because of their high installation price; traditional, passive AC devices are perceived to have a cost advantage. Furthermore, though controller-based options for grid reinforcement are attractive, they are not well understood, and operating experience with another innovative technology, HVDC systems, suggests that use of new control devices may result in significant and unforeseen interactions with other equipment. Although these problems can be largely addressed with WAMS, their costs are unclear, and the consequences of controller malfunctions can be very serious. Some legal opinion holds that the liabilities from such malfunctions will be substantially greater than those faced by utilities before industry restructuring (Fleishman 1997, Roman 1999). Such considerations weigh on the side of grid reinforcement through less technically demanding means even though the return on investment may also be smaller.

Very few utilities are in a position to break this impasse as the management functions for which high-level technologies like FACTS are of primary relevance are passing from the utilities to a newly evolving infrastructure based upon Regional Transmission Organizations (RTOs), Independent System Operators (ISOs), and other entities. This transition is far from complete in most areas of the U.S., and as yet there is no "design template" for the nature and the technology needs of this new infrastructure.

The Evolving Infrastructure for Transmission Management

The movement of operation and planning responsibilities from their place in the vertically integrated utility structure to the evolving new and restructured organizations has greatly weakened the essential dialogue between technology developers and users. Although this paper focuses on advanced transmission technologies, these technologies cannot be adequately discussed outside the context of the institutional framework within which they will be used. Development of advanced technology must be closely linked to its actual deployment for operational use. Together, these activities should reflect, serve, and keep pace with the evolving infrastructure needs of transmission organizations. Frameworks that discourage technology deployment will eventually inhibit its development. Unfortunately, the current uncertainty has produced exactly this effect.

To simplify our discussion, we assume that primary responsibility for grid management is assigned to an RTO. The following unknowns are of special concern:

- definition of RTO functions and resources,
- relationship between RTO and control areas,
- access to and sharing of operational information, and
- timeline for deployment of the supporting infrastructure for RTO operations.

Uncertainties about the evolving institutional framework for transmission management impede timely development and deployment of requisite technology. Key unknowns include:

- what functionalities require technical support and where they will be located within the overall infrastructure;
- what level of technological sophistication can be rationalized, accommodated, and supported at specific locations within the grid management infrastructure;
- how to accommodate the risks associated with operational use of prototypes;
- what extensions or refinements may be needed before particular technologies can provide full value in power system environments; and
- what the role will be of the RTO and other grid management entities in the overall R&D infrastructure serving power transmission needs.

Resolving these uncertainties in a timely manner may require that national energy policy address the infrastructure of transmission management. For the immediate future, the best course may be for policy makers to seek counsel from entities that are still involved in higher levels of grid management.

Performance Challenges to a New Generation of Transmission Technology

Many technologies, some surprising, are applicable to large power systems. Some hardware whose application to power systems may not be obvious at first include: acoustical radar to locate buried objects, radiation sensors to detect incipient failure in connectors or insulators, robotic vehicles (including unmanned aircraft) to examine the condition of transmission lines, specialized devices to mitigate the waveform pollution associated with some lighting technologies, the NASA Advanced Composition Explorer satellite (located more than one million miles from earth) to provide early warning of geomagnetic storms, and intruder alarms at unmanned facilities. Life sciences applications include study of: the biological effects of electromagnetic fields, the environmental impacts of a proposed transmission line on forest cover and wildlife, the function of naturally occurring microbes that can safely digest toxic spills, and the social/biological factors involved in management of large river systems. We can add to this a vast array of applications in materials science, advanced hardware and fuels, information systems, mathematical modeling and analysis, process automation, risk management, and decision support systems.

This paper's purpose is not to inventory the possible technology options. Recent studies by EPRI (EPRI 1997, EPRI 2001) present massive inventories with projections of likely merits, and a long series of DOE studies examines the subject from the perspective of national needs (DOE 1980-2000). The opportunities have not changed much in a decade, but the needs have become much more acute.

The subsections below list the strategic challenges that can be addressed through enhanced technology. Each challenge is stated as a functionality that will improve the overall performance of the NTG. Candidate technologies to meet each challenge are briefly discussed, and their current state of development is noted. An extensive, partial listing of new equipment technologies that could be applied to the NTG is given in Appendix A.

Technology Challenge #1: Broader Coordination of Grid Management

DOE's National Power Grid Study of 1980 notes that "Coordinated power system planning, development and operation results in reduction in fixed costs, reduction in operating costs, lower risks, and better utilization of natural resources." The report also lists impediments to full realization. The issues raised then have been rearticulated many times since; they are persistent, basic forces in the development of large power systems.

What has changed is the context within which these forces operate. There is now an artificial information barrier between generation and transmission, and coordination across that barrier is indirect (e.g., based upon market signals). However, direct coordination across broad geographical areas has become much more feasible from a technical standpoint and is directly consistent with the objectives of industry restructuring and the effective functioning of the national transmission grid.

A recent Federal Energy Regulatory Commission (FERC) directive assigning ultimate responsibility for grid management to a few "mega-RTOs" is a step toward the institutional framework needed for truly wide area management of the NTG. Although the details of this framework are still to be worked out, information technologies will be key to the infrastructure. Integrated computer models must quickly and accurately support power-flow calculation, risk assessment, and emergency management across broad areas of North America where such activities are now performed piecemeal. Modeling studies must be reinforced by measured information, which is also needed to assure the validity of the models. Great volumes of operational data must be integrated and sifted for indications of hidden problems or to facilitate general grid management decisions. High capacity data links are needed among control centers and RTOs. High capacity information links of a different kind are needed to achieve "virtual work team" collaboration among supporting staff who may be located at widely separated locations and institutions. All of these improvements must be made with close attention to the overall security of the information process and facilities.

One approach to real-time operational system data would be to continue the current utility strategy of treating practically all such data as proprietary. Currently, only a small group of (often overworked) utility employees has access to system operational data. Although the reasons that utilities would like to keep the details of their operations hidden from public scrutiny are clear, a significant lesson from the recent electricity crisis in California is that when the grid fails, the public pays the price. Furthermore, the shared nature of the transmission grid and the fact that problems in one area can rapidly propagate throughout the entire grid make the electricity industry unique. The data that are public by federal mandate, such as FERC Form 715 filings, are helpful, but errors, such as base-case-limit violations, restrict the usefulness of these data. The release of highly processed information, such as the posting of available transmission capacity (ATC) or Locational Marginal Price (LMP) data on the Open Access Same-Time Information System (OASIS), is also helpful, but the calculations are impossible to verify or extend if the raw source data are not available.

An alternative approach would be public posting of near-real-time operational data. FERC did not prohibit access by generators to transmission data; rather, it required that such access be non-discriminatory. Freeing the data might free the industry's entrepreneurial spirit. As a result of restructuring, the number of players interested in knowing the operational state of the grid has skyrocketed from a handful of vertically integrated utilities to hundreds of marketers, independent generators, regulators, and consultants. Currently, generation companies are making investment decisions about new plants, which cost hundreds of millions of dollars, based on very limited information about actual grid operation. This situation is almost guaranteed to produce some disastrous choices. New transmission lines may be needed, but how can governmental agencies and the public make informed decisions when information about actual grid operation is unavailable? New transmission technologies are being developed, but how can their manufacturers make informed business decisions about which technologies to pursue when they have limited means to determine need?

If data were available, third parties might quickly develop innovative informational products to meet the industry's needs. Third parties interested in selling to a market much larger than the traditional utility EMS market could develop many of the tool sets needed for analyzing large RTOs. Even with the limited data available today, third parties are offering some innovative grid analysis and visualization products. Increased availability of data might also allow for more effective independent oversight of grid operation. Currently, there is little oversight. Federal and state regulatory agencies do not have the tools or the data to effectively oversee grid activities, and because there is no access to these data, there is little incentive for third parties to develop the requisite tools.

Useful data might include transmission device status information, real and reactive power flows for transmission facilities, voltages and frequencies at key points within the transmission network, along with more processed data such as ATC and LMP information. Given the current low cost of computer storage and the availability of high-speed data communication, dissemination of these data should be simple. For example, the posting of hourly snapshots of 5,000 flow values and 2,000 status values would require less than one megabyte of storage per day. Immediate public release of some data, such as generator offers, would not be appropriate.

As a result of increased concern about possible terrorist activity, public access to transmission system information has actually become substantially more restricted. For example, on October 11, 2001 FERC restricted public access to a substantial amount of energy facility data, including the FERC Form 715 data. This is unfortunate and, for the most part, unnecessary. Public access to a large amount of additional information is possible without jeopardizing either the physical security of the transmission system or legitimate proprietary concerns of grid participants. Without such data it will become increasingly difficult for market participants to effectively utilize the NTG. As a minimum, there is a need for an industry-wide discussion on what data can legitimately be made public and what data must remain proprietary, and on the best mechanism for the release of this data.

Regardless of whether data remain proprietary within RTOs or enter the public domain, key technologies for broad data coordination are digital communications, high-performance computing, computer mathematics, data management and mining, collaboration networks, information security, and operations analysis. Discussion of these subjects and partial templates for the needed R&D can be found in reports issued by the DOE and EPRI as part of the ongoing WAMS effort (DOE 1999). Much R&D for data coordination would draw upon and directly reinforce the evolving Reliability Information Network by which Regional Security Coordinators share grid information in near real time.

Technology Challenge #2: Knowing the Limits of Safe Operation

Full use of transmission capacity means that the system will be loaded close to the "edge" of safe operation. In recent years, many cases have revealed this edge to be much closer than had been expected. Less dramatic yet of equal or greater importance are the many undocumented situations in which grid capacity has been significantly underutilized because lack of knowledge about real system limits resulted in overly conservative operation. Safe operating limits are defined by a multiplicity of system conditions that have become more difficult to anticipate, model, and measure directly.

Electrical conditions on the transmission system may not be fully known, and even if they were, their full implications might not be. It is not possible to anticipate and study all possible conditions, and the computer models used in studies are sometimes sufficiently unrealistic that they produce misleading results. Partial remedies would be to augment modeling results with measured data and to calibrate models against observed system behavior.

The challenge here is partly technical and partly institutional. On the technical side, the determination of safe operating ranges requires a variety of different inputs that are associated with a variety of different time frames, all of which are dependent on the accuracy of the underlying models and of the data provided to those models. The longest planning time frame is associated with operational limits set by planners weeks or months ahead. These usually include transient stability limitations, oscillatory stability limitations, and voltage stability limitations and are conditional on long-term forecasts of customer demand and overall power system resources. Because assumed conditions are seldom the same as actual operating conditions, the limits are intended to be sufficiently conservative that modest differences between predicted and actual operating conditions can be accommodated through later planning adjustments. These adjustments take place in a shorter time frame that supports planning for several hours to several days in advance. This shorter time frame permits more precise forecasts of pending system conditions, but it restricts the opportunity for in-depth analysis and the range of operational alternatives that can be considered. The planning and decision tools used in this time frame, though sometimes ad hoc, often provide market-critical information such as ATC to be communicated to market participants via the OASIS. Finally, in near-real time, system operators use the EMS to observe and assess the actual status of the power system. On-line tools, such as real-time power flow and contingency analysis, provide guidance for managing situations in which real-time conditions are substantially different from what was planned.

Ideally, the planning process insures that maximum transmission capability is available to the power market while system reliability is maintained. The challenge is that errors may arise at any point in the process. One problem, as noted above, is that the electrical conditions and their implications may not be fully known. The system must be observed in such a way that system operators receive timely and complete information. Complicating observation of the system is what is known as the issue of "seams" between areas of the grid. Currently in the U.S. there are approximately 140 different utility control areas and 20 higher-level security coordinators, each trying to monitor its portion of the grid. As EPRI (2001) notes, "each control entity is like its own sovereign nation as far as market and data practices go, and coordinating power transfers that extend beyond the borders of an entity entails complex technical tradeoff analyses consistent with how the grid actually responds to inter-regional power flows." Power flows easily between control areas, and, as illustrated by the example in Figure 3, the transactions and control actions in one or two areas can have grid-wide implications.

Another source of error in the planning process is that assumed conditions may differ widely from real-time conditions. If the planning limits are too high, or if some market-driven transfers become too heavy, the system may be in danger of widespread, cascading outages. In these circumstances, some market activities would have to be curtailed through actions such as TLR (transmission loading relief). Alternatively, planning limits may be too low or ATC results too conservative. In these cases, the transmission grid may be underutilized, with the market sending erroneous signals to adjust more generation or transmission than needed. One example is transmission line thermal limits, which in many markets are the limiting constraints on ATC. The amount of power that can be transferred along a line is highly dependent on ambient weather conditions. Yet fixed limits are used in most cases (sometimes these limits differ in winter and summer). Better estimation of these limits, perhaps coupled with real-time measurement of conductor temperature or sag, could result in a significant increase in ATC. The seams issue arises here as well because each security coordinator is simultaneously performing studies to determine transmission capability, usually without detailed knowledge of what its neighbors are doing.

A third source of error is flawed conceptual formulation of the models that are used to predict power system behavior under highly stressed conditions. A common theme in the post-mortem analyses of major system disturbances is that the models did not correctly predict or replicate actual system behavior. One recent example is the near-voltage-collapse in the Pennsylvania-New Jersey- Maryland connection (PJM) during July 1999 (DOE 2000). Effective intervention by PJM operators averted a loss of load, in large part as a result of EMS technology that afforded unusually good real-time observation of grid voltages. Later analysis revealed substantial optimism in the assumed capabilities of many PJM generators to support system voltages (through reactive power generation) while producing specific levels of real power (megawatts). These findings parallel utility experience around the world: the actual capability and behavior of a thermal power plant may be radically different from that indicated by generator models or nameplates. This seems especially true of gas-fired turbines, which constitute almost all new plant construction. (It has been reported that some operators outside the U.S. take their plants to maximum output every hour, just to establish capability limits.) The emerging picture is that reserve generation capability for emergency use is much smaller than previously believed, and that financial considerations may encourage plant operations changes that compound the problem in ways that system planners are just now starting to recognize. This is one of several issues that the U.S. Department of Energy (DOE) has been monitoring through its Transmission Reliability Program.

A related issue associated with the NTG study is the need for better computer modeling of the interrelationships between electricity markets and the NTG. An accurate assessment of the cost impact of the NTG bottlenecks on market operation requires detailed, time-varying analysis (e.g., hour by hour) of an entire interconnected system. Since in some portions of the NTG the constraints are due to reactive/voltage problems, traditional, linear transportation-based models are not adequate. Such analysis could prove crucial to determining the optimal locations for expanded transmission capacity. Previously, such detailed analysis had been computationally prohibitive. However, faster computer processors and greater availability of parallel processing are rapidly removing these barriers. Development of the necessary computer models and algorithms for this analysis has also been hindered by lack of availability of the interconnect-wide data needed to perform such an analysis.

From a technical viewpoint, the immediate solution is to continue the incremental changes that have been taking place. These include developing enhanced real-time systems for measurement-based information, improved tools for system analysis and visualization, improved data communication between control centers and security coordinators, increased utilization of improved computer technology to move system limit calculations closer to real time, and increased feedback of system operational data to system planners to improve the calibration of models against observed system behavior. There is a significant need to improve our understanding of the fundamental behavior of the power system and the conditions or events that lead to system failure. Improved models are an essential element of this effort. Proactive federal involvement in the development of interconnect-wide models and tools could be quite helpful.

The solutions noted above neglect relevant institutional issues. Simply stated, in most markets there is a fundamental dichotomy between the commercial participants and the transmission managers who make the market possible. Unlike the commercial participants, the managers have no clear "pay for performance" mechanism for recovering their financial investments. The absence of such a mechanism has fostered a spiraling decline in staffing, priority, and overall resources given to system planning. Calibration of planning models and direct assessment of power system behavior should be integral to the planning process. The industry has a growing wealth of data to support this conclusion, not only from its EMS facilities but also from a host of sources including integrated phasor measurement systems and substation-based data recorders. Unfortunately, most of the utility staff with access to these data are too burdened by day-to-day tasks to use the data or the tools required to analyze the data. Repeated staff reductions have meant that this complex task has almost vanished from utility organizational charts. As highlighted in EPRI (2001), the linkages among markets, technology, and policy are fundamental and must be understood and adjusted to best effect.

Key technologies for this understanding are essentially the same as those noted for Technology Challenge #1. Special requirements include mathematical systems theory, signal analysis, operations analysis, and probabilistic methodology.

Technology Challenge #3: Extending the Controllability of Network Flow

A higher degree of power flow control than is currently possible is a very attractive means to improve utilization of transmission resources. Conventional power-flow control devices include series capacitors to reduce line impedance, phase shifters, and shunt devices that are attached to the ends of a line to adjust voltages. A far higher degree of control is provided by HVDC transmission equipment and FACTS technology. The so-called NGH (a device, in which power electronics facilitate safe application of a conventional series capacitor) appears to be a precursor to FACTS technology.

Devices that improve flow control can be used individually or in combination to directly regulate power routing on the grid and to relieve dynamic problems that may limit grid utilization. Control of this sort is a very attractive alternative to the construction of new or stronger lines. This is not the whole story, however, because power system controls are subject to errors in the control law on which they are based or the models from which the control law is developed. (This is in contrast to the functional reliability of a new transmission line or power plant, which is almost synonymous with its hardware reliability.) Because of this vulnerability, the overall reliability of large-scale control systems cannot be assessed or assured by the straightforward and proven methods that are used in construction-based reinforcements to the grid. How, then, should the choice be made between controls and construction of new transmission capacity?

A full demonstration of controller reliability is rarely possible. It is always necessary to trade controller benefits against the risks associated with closing a high-power control loop around system dynamics that are not fully observed and not fully understood. Controller reliability must be assessed broadly, incorporating engineering judgment and sound practice. Uncertainty should be mitigated where possible, but this is often a slow and technically difficult process (Hauer & Hunt 1996). Whatever uncertainty cannot be mitigated should be accommodated in controller design and operation. All of these measures require that wide-area control systems be supported by wide-area information systems, and that the grid management infrastructure include an appropriate degree of technical expertise in control engineering (Hauer & Taylor 1998).

Wide-area control, whether using FACTS or less advanced technologies, offers many benefits to the next-generation national transmission grid. A recent FACTS installation in Brazil is especially noteworthy; it links two regional systems with an AC line plus two thyristor-controlled series capacitor (TCSC) units. Prior to this, a DC line would have been the inevitable and more expensive choice.

Here in the U.S., the installation by the New York Power Authority of a Convertible Static Compensator (CSC) FACTS device has increased the power transfers on the Utica-Albany power corridor by 60 MW in its initial phase, with a projected increase to 240 MW when Phase Two is completed in 2002. However, it is important to place these numbers in context. Overall, the peak electricity demand in New York State is approximately 30,000 MW, with approximately half the demand in upstate New York and the remainder in New York City and Long Island. The current import capability from the upstate region to the city and Long Island is approximately 4,500 MW, with another 2,000 MW coming from PJM. Therefore, the increase from the CSC device is approximately five percent of the current capacity, and about 1.5% of the peak New York City/Long Island load.

A proposal that complements the use of FACTS devices to achieve better network control is to break up the current Eastern and Western Interconnections into smaller, more manageable synchronous interconnections. These smaller interconnections (which could correspond to existing regional reliability councils) would be joined by HVDC ties; the size of the ties would match existing transmission transfer capabilities (De Steese and Dagle 1997). The use of HVDC between the interconnections would permit complete control of power flows between interconnections, completely eliminating long-distance loop flow. Loop flow would still be an issue within the interconnections, but their smaller size would make this flow easier to manage. Of course, such wide-scale dismantling of the Eastern and Western Interconnections would require major investment in new HVDC lines and could present a host of new, unforeseen technical problems.

A key challenge to the use of advanced technology to achieve better network control is that it is a "high tech" option entering the business environment for utilities, ISOs, and other grid managers, which today favors "low tech" investments. Advanced control technology is often characterized by high initial costs and ongoing maintenance and operation costs. In addition, use of HVDC or FACTS devices can result in higher power losses, with typical converter losses of one or two percent of flow. For most utilities, cost-benefit analysis currently favors doing nothing, letting new generation take care of the need, or investing in familiar passive AC devices. Outstanding issues to be addressed before advanced technologies can compete in such an environment include the need for operational experience, quantification of benefits, and resolution of impediments to reliable control in high-performance applications.

High-performance hardware for wide-area control is ready for use; conventional technologies have served local and regional needs for many years. Full use of wide-area control demands an improved infrastructure for wide-area information. WAMS, the information counterpart to FACTS control, is expressly designed to provide this infrastructure.

Technology Challenge #4: Dealing with Operational Uncertainty

Providing reliable and economical electric power calls for two parallel efforts related to uncertainty. The first is to reduce uncertainty by means of information that is better and more timely than what is currently available. The second is to accommodate the residual uncertainty through the use of appropriate decision tools.

In 1996, two massive breakups of the western power system demonstrated the need for improved resources to deal with the unexpected. As noted above, data collected in real time at BPA's Dittmer control center contained subtle but definite indications of oscillatory instability for several minutes prior to the actual breakup on August 10. BPA operators also reported that hints of weak voltage support may have been present for much longer. Had there been means for converting these hints to unambiguous operator alerts, that breakup might have been avoided entirely.

Contradicting actual system behavior, later studies performed with standard WSCC models (adjusted to the conditions and events leading to the breakup) indicated that the system had excellent dynamic stability. Enhanced models, internally adjusted to match observed system behavior, are outwardly more realistic but still suspect. Modeling errors are one of many uncertainties that improved resources for grid management must accommodate.

Even if suitable planning models had been available, operating conditions preceding the August 10 breakup were far from nominal and had not been examined in system reliability studies. These studies are generally performed weeks to months in advance, and planners cannot anticipate all combinations of seemingly minor outages that may be part of the operation of a large power system. Planning uncertainty and its attendant risks can be mitigated in part if system capacity studies are performed with a much shorter forecasting horizon and based on reasonable extrapolations of current operating conditions. This approach calls for much broader real-time access to those conditions than any one regional control center now provides. The requisite computer tools are directly consistent with the framework envisioned for dynamic security assessment (DSA), however. This is also true of the measurement-based operator alerts mentioned earlier although the mathematics needed is quite different.

The combinatorial problem for longer-term planning remains especially formidable. The number of likely contingency patterns, already huge, is becoming even larger as the market seeks energy transactions across longer distances. Future practices may also represent model errors as contingencies. Even without this change, direct examination of each individual contingency pattern is not feasible. Contingency evaluation is a further challenge. Never a simple matter, it must now reflect new linkages between system reliability and market economics. Decisions must be rendered more rapidly than before despite increased uncertainty and sometimes increased risk.

Reducing and accommodating these uncertainties requires a broad, multi-faceted effort. Requisite technologies include:

- Improved real-time tools to examine power system signals for warnings of dangerous behavior. The more rapidly that operator intervention is initiated, the more likely that a blackout can be averted.
- Improved visualization, giving operators a bird's-eye view of the power system.
- Mathematical criteria, tools, and procedures for reducing and/or characterizing errors in power system models.
- Characterizations and probabilistic models for uncertainties in power-system resources and operating conditions.
- Probabilistic models, tools, and methodologies for collective examination of contingencies that are now considered individually.
- Cost models for quantifying the overall impact of contingencies and ranking them accordingly. It is essential that these models be realistic and suitable for use as standards for planning and operation of the overall transmission grid.
- Risk management tools, based on the above probabilistic models of contingencies and their costs, that "optimize" use of the electricity system while maintaining requisite levels of reliability.

Development of the technology noted above can likely be expedited through technology transfers from outside the power industry. Even so, there are special and difficult problems. The knowledge base for actual power system behavior, required both to define the subject technologies and obtain best value from their use, is not well evolved. The knowledge base and the technologies should develop together, in or close to a practical utility environment.

Furthermore, probabilistic planning is not just a smooth extrapolation of current practices. It requires new skills and practices. These practices must be developed, evaluated against those now in use, and then approved for use at the RTO level. These matters should be addressed at the earliest possible stage of technology development.

Technology Challenge #5: A Grid that Heals Itself

The interconnection of large power systems into still larger ones greatly increases the possibilities for widespread failure. Grid managers go to great lengths to anticipate and avoid such failure. However, at some level of complexity, anticipation and avoidance become too difficult or expensive.

A variety of lessons can be extracted from the 1996 breakups of the western power system. One of these lessons is that when prevention of system breakups becomes impractical, it is time to focus on minimizing the consequences. A triage approach has long been characteristic of grid operations; the operation of individual relays is a good example of removal of a small portion of the system to save the whole. On a broader basis, the use of under-frequency load shedding has been a very effective means of saving the grid from frequency decay at a cost of perhaps five or 10 percent of total load. Limited self-healing is also found in the use of automatic circuit-break reclosing after events such as the loss of a line from a lightning strike.

What is new since 1996 is a shift in emphasis from aggressive use of preventive control, accepting possible loss of some load, to consideration of "dynamic islanding" strategies that accommodate an occasional breakup while minimizing its impacts and assuring smooth restoration of electricity services. Dynamic islanding would involve:

- Emergency, possibly localized, controls that separate the power system into either predefined islands or dynamically defined islands as dictated by conditions that are sensed locally.
- Islanding options designed for minimal loss of service, given proper control assistance.
- Islanding and restoration as a continuous smooth process controlled by FACTS, HVDC, or automatic generation control.
- Conversion of some AC lines to DC. This change is particularly attractive for lines that would otherwise become stranded assets under the pressure of new generation installed close to major loads.

Avoiding just one catastrophic event would likely payback much of the investment cost of FACTS technology and the associated infrastructure. But there are both technical and institutional concerns. From a technical point of view, developing even limited islanding capability, let alone grid self-healing, is an immense challenge. During islanding, the two new islands will be simultaneously presented with a combination of potentially large initial generation/load imbalances and changes in line flows as existing tie flows are eliminated. Frequency regulation characteristics will also change due to the changes in total inertia. Although a dynamic islanding scheme has been implemented on the WSCC system, its use on the Eastern system would be much more involved because of the higher density of tie lines. From an institutional point of view, incentives would be needed to encourage the development of islanding schemes. It appears that only an ISO or RTO would in a strong business position to assume the costs given the geographical area involved.

Technology Challenge #6: More Power in Less Space

There are many reasons to seek power system equipment that requires a minimum of space. New rights of way for transmission lines are environmentally intrusive, difficult to route, and subject to a very slow approval process as local authorities are increasingly reluctant to approve projects that do not address local need. These problems tend to be less severe for underground transmission cables, but new routes or added space for underground cables may be impossible in highly urbanized environments like Chicago or New York City; costs inhibit the use of underground cables in less urban areas. Substations, generators, and transformers all benefit from having a smaller "footprint," especially if the equipment itself is smaller and more portable.

So how can we fit more power into a given space, or into even less space? Conventional solutions include “reconductoring” lines to carry more current at the same voltage, revising lines to operate at higher voltage (if possible), and converting AC lines to DC. The use of composite materials is a promising approach for reconductoring. Traditionally, overhead transmission lines have been constructed using aluminum conductors steel reinforced (ACSR) consisting of stranded aluminum about a stranded steel core. The aluminum carries the current, and the steel provides mechanical support. The limiting constraint for such lines is sag resulting from heating. A new approach for increasing conductor current capacity without increasing weight is to replace the steel core with a composite material, such as glass-fiber. Because the tensile strength of the glass is up to 250 percent of the strength of steel, the composite conductors are lighter and stronger and could have higher current capacity. Reduction in sag allows tighter spacing of conductors, which reduces magnetic fields and might mean that new conductors could be added in existing rights of way.

A complementary approach to increasing the available capacity of existing AC lines is to dynamically determine the actual conductor limits. The thermal capacity of an overhead line is highly dependent on ambient conditions; there is more power-transfer capacity when the line is being operated in cold, windy conditions than when it is operating in hot, calm weather. Approaches to dynamically determining conductor limits include either direct measure of conductor temperatures or use of a differential global positioning system (GPS) to directly measure the sag of critical spans.

For higher-voltage lines, limits are usually based on “loadability” constraints rather than thermal limits. The loadability of a line that cannot be operated close to its thermal limit can often be improved by compensating devices or full FACTS control. Another promising though relatively conventional technology is compact transmission lines that are reconfigured to carry more power (at the expense of increased losses).

An alternative to overhead lines is buried cables. Several different cable designs can be used; oil-impregnated paper-insulated pipes are the most common. A key advantage of underground cables is that they usually face little public opposition. Also, the closer spacing of the conductors results in greatly reduced electromagnetic fields (EMFs) because of phase cancellation. Finally, underground cables are not subject to weather and thus may be more reliable than aboveground lines. The key disadvantage of buried cables is cost. With cost ratios of up to ten times for rural high-voltage lines, it is nearly always more economical to build overhead lines unless one is in an urban area. Also, the length of AC cables is limited by their relatively high capacitance; uncompensated cables may be limited to perhaps 25 miles. Finally, over the long term, underground cables may not be as reliable as overhead lines because it takes substantially longer to locate and correct problems with buried lines.

Truly strategic improvements in compactness call for new technologies like supercapacitors, transformerless HVDC, and cryogenically enhanced devices. Cryogenic operation (i.e., operation at unusually low temperatures, which may or may not be low enough to achieve superconductivity) reduces or eliminates resistance in an electrical device and thereby allows a several-fold in increase in its power-handling capacity. This benefit can be exploited either as increased capacity within given size and weight constraints or as equivalent performance in a much smaller and lighter package. However, cryogenic devices also have disadvantages. For example, some super-conducting devices operate with extremely high currents and thus radiate very intense magnetic fields. As a general rule, the introduction of cryogenic cooling adds complexity to a device, so a utility using cryogenic devices would have to hire employees with the specific skills to maintain these devices. Cryogenic devices also generally require long cool-down times, up to a week or more for some such as super-conducting magnetic energy storage (SMES) and large transformers. Certain maintenance and repair procedures may require warming the devices up to ambient temperature, which takes a similar amount of time. This characteristic may be an unacceptable operational constraint.

Cryogenic devices now include cables, transformers, current limiters, switches, generators, and energy storage devices (SMES). These devices are at stages of development ranging from working prototypes to a few commercially successful products. The underlying base technologies are the subject of active research, and the technical feasibility of cryogenics in general is increasing steadily. As with FACTS, the chief impediment to practical deployment is the initial investment.

Another partial solution to current difficulties with obtaining new rights of way is to utilize non-traditional transmission paths, such as submarine cables. One such project currently under consideration, known as the Neptune Project, seeks initially to connect 345-kV substations in Brooklyn and Long Island NY with a 345-kV substation in northern New Jersey via two 600-MW HVDC cables buried in trenches on the Atlantic Ocean floor. Subsequent phases seek to link New York City with a substation in New Brunswick, Canada using a 1,200-MW submarine HVDC; cables added later would join Boston and other New England locations. Another project under consideration seeks to link Ontario, Canada to either Ohio or Pennsylvania using several HVDC cables under Lake Erie. Given the large number of urban load centers located on the oceans or Great Lakes, the commercial success of one such submarine HVDC project could lead to many more. The advantage of such an installation is that no eminent domain authority is needed to obtain the water rights of way, and the relatively small land-based converter stations that are required can be located to bring power directly into urban load centers. Due consideration must be given to avoid harming the aquatic environment, with the cables routed to avoid active fishing and sensitive environmental areas.

Technology Challenge #7: Assessing New Technologies Using Life-Cycle Analysis

Investments in new technologies can be both necessary and dangerous. Investments in the wrong technologies can lead to disaster. Timely new ways to reduce costs and improve performance are essential to business survival. Utilities tend to be very cautious in investing in new technology.

One reason for their caution is that the actual merits of any new technology can be difficult to estimate in advance. New or advanced technologies are very likely to have hidden costs (and may also have hidden benefits). Some technologies are “fragile,” requiring significant engineering design or unforeseen maintenance. Others are “intrusive” in that their use calls for major changes in associated technologies and methods. Still others produce long-term environmental problems, such as the disposal of hazardous materials used in their construction. And some technologies might fail in a catastrophic manner that endangers human health and safety.

All utilities are well aware of these possibilities, but few individual utilities have the resources to assess them. Suitable resources can be assembled on a collaborative basis, but a suitable assessment methodology must also be developed.

Full assessment of new technologies calls for a life-cycle analysis that considers all costs and all benefits, with suitable consideration of regulatory constraints and other external or uncertain factors. To be inclusive, life-cycle analysis should start with production of the technology and consider impacts upon the economy, health and safety, the natural environment, and other elements of the public good. The analysis continues from this point through all expected uses of the product to its eventual recycling or disposal by other means.

The electric power industry seldom makes equipment acquisitions using such thorough analysis. The industry will also argue, reasonably, that it cannot afford in-depth consideration of all aspects of the public good in everyday business decisions. However, the norm for much equipment procurement is to accept the minimum bid. This practice has already populated the national grid with a large amount of energy-inefficient equipment. The practice of life cycle cost optimization should at least consider the full range of tradeoffs, comparing benefits with the total cost of ownership for the life of the equipment. Life-cycle costs include acquisition costs as well as costs of capital, energy, operations, maintenance, and disposal.

Technology Challenge #8: The Intelligent Energy System

Information is the crosscutting issue in all transmission grid technology challenges. WAMS and FACTS share an underlying vision of an Intelligent Energy System (IES) in which "intelligent" planning, design, control, and operation of system assets are the primary means for meeting energy demands. An IES might well involve coordinated operation of the electrical and gas energy systems, with the gas system providing virtual storage for electrical energy. The IES would certainly draw upon FACTS technology for the routing of electrical power and upon dispersed assets such as distributed generation, energy conservation, direct or indirect load control, and renewable energy sources. WAMS is a critical element in the information infrastructure needed to make the IES possible and to insure power system reliability.

The vision of an IES extends beyond FACTS and perhaps beyond WAMS. Additional elements include protective relay systems that "adapt" to widely variable power flows, diagnostic tools to reduce human error during system maintenance, enhanced information tools for emergency management, and "intelligent" data miners that sift operating records for evidence of needed maintenance. Some specific examples, extracted from much more detailed treatments in PNNL (1999), are presented below.

Protective Controls—Relay Coordination

Containing a sizeable disturbance usually requires appropriate action by several relays. Communication among the relays is often indirect, through the power system itself. Effectively designed direct communication among relays would make coordination more reliable from the hardware perspective. Relays, like transducers and feedback controllers, are signal-processing devices that have their own dynamics and modes of failure. Some relays sense conditions (like phase imbalance or boiler pressure) that power-system planners cannot readily model. At present, there are few engineering tools for coordinating wide-area relay systems.

Large power systems are sometimes operated in ways that were not foreseen when relay settings were established. It is not at all apparent that fixed relay settings can accommodate the increasingly busy market or, even more difficult, the islanding that has been seen recently in North America. It may be that relay-based controls, like feedback controls, will need some form of parameter scheduling to cope with such variability. The required communications could be highly vulnerable from a security standpoint, however, so precautions against the growing threat of "cyber attack" would be needed.

Several recent grid events suggest that there are still questions to be resolved regarding the basic strategy or economics of bus protective systems (PNNL 1999). In the western system breakup of December 14, 1994, it appears that "bus geometry" forced an otherwise unnecessary line trip at the Borah substation in Idaho and led directly to the system breakup. Bus geometry was also a factor when all transmission to San Francisco was lost on December 8, 1998. Following routine maintenance at the San Mateo substation, a breaker was closed while protective grounds were still attached. The resulting fault tripped all lines to the San Mateo bus because a differential relay system had not been fully restored to service. An appropriate diagnostic tool would have indicated this condition and warned that the grounds had not been removed.

Emergency Management—the Northeast Ice Storm of 1998

Emergency management resources of the Northeast Power Coordinating Council were severely tested when a series of exceptionally severe ice storms struck large areas in New York, New England, Ontario, Quebec, and the Maritime provinces between January 5 and 10, 1998. The worst freezing rains ever recorded in that region deposited ice up to three inches thick. Resulting damage to transmission and distribution was severe (more than 770 towers collapsed).

The event resulted in some valuable lessons regarding system restoration. Emergency preparedness, cooperative arrangements among utilities and with civil authorities, integrated access to detailed outage information, and an innovative approach to field repairs were all found to be particularly valuable. The disturbance report mentions that information from remotely accessible, microprocessor-based fault locator relays was instrumental in quickly identifying and locating problems. Implied in the report is that the restoration strategy amounted to what mathematicians call a "stochastic game," in which some risks were taken in order to make maximum service improvements in the least time—and with imperfect information about system capability.

Technology Challenge #9: Physical and Cyber Security of the Transmission Grid

Given the recent increased awareness of the possibility of terrorist activity, it seems especially pressing to address the physical security of the NTG. (This paper focuses on the transmission system only and does not address the physical security of individual generation stations.) We consider transmission security in relation to the risk of physical destruction of system elements and concerns about cyber security.

In relation to concerns about physical destruction, the blessing and the curse of the transmission grid is its immense size. In the U.S. there are currently more than 150,000 miles of transmission lines that are 230 kV or higher, and there are many tens of thousands more miles at lower voltage levels. In both the Eastern and Western Interconnects, there are tens of thousands of individual transmission lines and many thousands of individual high-voltage transformers. The curse is that such a system is impossible to "secure;" there is no effective means to prevent a determined group of individuals from destroying a portion of the grid. But the blessing is that they could destroy only a miniscule portion. In addition, any destruction aimed of individual towers would have temporary effects. Given the regular occurrences of tornadoes, hurricanes, ice storms, and earthquakes, the transmission system has been designed to take its share of individual hits and continue to function. And the utility industry is quite adept at quickly repairing the damage done from such natural occurrences. It would be very difficult for even a large, well-organized group to duplicate the physical damage done by even a moderate ice storm.

The issue is whether a major disruption could be caused if various key grid facilities, such as electric substations or rights of way with many individual circuits, were selectively targeted. The answer is "yes" if enough key facilities were destroyed. But the impacts would likely be temporary because transmission lines could relatively quickly be rerouted around most substations. Some equipment (e.g., transformers) would be vulnerable and difficult to replace. The destruction of multiple transmission stations by a knowledgeable saboteur with a highly organized attack could result in substantial damage and long-term blackouts.

Another concern is security of information systems or cyber security. The increasing reliance of the electric power industry on communications and control systems together with the remarkable advance of electronic intrusion technologies and techniques make the restructuring utility industry particularly vulnerable to disruptions resulting from inadequate safeguards and security capabilities. More points of entry into command and control systems will become available to potentially hostile individuals or organizations. Many of these entry points will differ from the points of access previously established to serve a vertically integrated utility industry. The advent of real-time power dispatching coupled with competition in retail power markets and many other challenges of operating in a restructured industry environment will greatly reduce the safety margins currently maintained by electric utilities. The utility system of the future could become much more vulnerable to corruption by skilled electronic intrusion from both inside and outside. A primary, emerging need in the utility industry is for development of new guidelines, policies, and standards for the selection and implementation of cost-effective security measures (EPRI 1996).

The protection of critical civilian infrastructure has been a national focus since the mid-1990s with the formation of the Presidential Commission on Critical Infrastructure Protection (PCCIP) in July 1996 and the Presidential Decision Directive 63 (PDD-63) on Critical Infrastructure Protection issued in May 1998. DOE is responsible for the electric power sector and the natural gas and oil production and storage sectors and has formally designated NERC and the National Petroleum Council (NPC) as liaison organizations. In

Meeting the Technology Challenges

April 2001, NERC published a white paper: *Approach to Action for the Electricity Sector* that outlines the electric power industry's plans for security against physical and cyber attack.

For lack of a clear "business case," new technology investments often involve more financial risk than any single utility (or new ISO) can accept. Motivating these investments will require some combination of definitive national policy along with market models for investment planning.

Institutional Issues

A formidable number of institutional issues hinder timely identification, development, and introduction of new technologies. Today's utilities are understandably reluctant to fund R&D that is not promptly and directly beneficial to them. Likewise, utility suppliers will not fund new transmission technology research if there is not a reasonable likelihood of an adequate return on the investment. Contrary to the premises under which EPRI was established separately from the DOE national laboratories, it is now difficult for EPRI to act as the coordinating umbrella organization for long-term R&D in the public interest. Much of the work produced by EPRI is essentially unavailable to the many nonmembers. The following "out-of-the-box" solutions should be considered:

- Apply a user fee to all institutions that engage in energy business. This fund would be used exclusively for energy R&D in the public interest, and all R&D results would be fully available to all energy business institutions.
- With suitable oversight provisions, disperse the above R&D fund through a DOE entity or a new public-service arm of EPRI (all institutions that engage in energy business would be members). It might be preferable to coordinate and consolidate these activities through a new umbrella organization for energy R&D.
- Engage industry experts in mentoring R&D and in-the-field assessments that are needed to close the gap between the development of new technology and its actual deployment for operational use.

Effective Utilization of Federal Resources

The federal government is very involved in the national grid through the federal utilities, including the TVA, the Power Marketing Administrations (PMAs), various elements of the U.S. Army Corps of Engineers and of the U.S. Bureau of Reclamation, as well as other entities. Collectively, the federal utilities operate "backbone" facilities for a large portion of the North American power system.

The federal government is also the ultimate steward for the staff skills, knowledge, and operational infrastructure of the federal utilities. These utilities are unique national resources of great value. They are immediately available to reinforce energy reliability in the public interest, a role in which they have long been a mainstay. Consideration should be given to the following ways to better utilize this resource:

- Fully engage the federal utilities as advisors and/or researchers in ongoing federal efforts to meet national energy needs.
- Draw on the federal utilities for field testing and operational assessment of new or prototype technologies. Give special attention to critical enabling technologies that have not drawn sufficient commercial interest to assure their timely evaluation and refinement.
- Identify critical resources provided by the federal utilities and integrate these resources into the national laboratory system. Support could be provided through a consortium arrangement among the national laboratories and federal utilities.
- Take immediate steps to establish a productive dialogue among all members of the proposed consortium and safely archive their collective institutional knowledge for future use.

Effective Utilization of Academic Resources

The electricity industry may be underutilizing the R&D potential of American universities. However, a contrary view holds that industry needs are primarily in development and that universities lack both the mission and staff continuity to proceed past the initial research phase. The proper relationship between university and industry has not been determined and should not be regarded as fixed. What is clear is that the dialogue between universities and the electricity industry is weaker than is the university-industry relationship in most other industries and that few universities have the direct industry involvement or the "institutional culture" that is needed for practical technology development in this area. Changing this situation might lead to a university system closer to the European model, in which many academics are part-time industry employees. Fundamental changes in the relationship between university and industry have many ramifications, and an open discussion of the matter would be timely.

One bright spot is the growing trend toward cooperative university/industry research centers. These centers seek to bridge university-industry gaps by directly involving industry in university research projects. This partnership helps projects maintain a degree of focus on problems currently facing the industry. The challenge for the universities involved in such centers is to demonstrate to their industrial members that membership fees represent money well spent.

In addition, there are growing numbers of faculty members involved in start-up companies in the power area. Universities nationwide are seeing a need to foster economic development in their local regions and states and to facilitate the transfer of university expertise and research to industry. Although a number of mechanisms exist to meet these goals, encouraging faculty with innovative ideas to form start-up companies is particularly promising as much of the country's innovation arises from entrepreneurial activity by small companies.

Advanced Technology Related Recommendations

Sustainable solutions require balances between generation, transmission, and demand; planning and operations; profit and risk; the roles of public and private institutions; and market forces and the public interest. The strategic need is not just for advanced technology in the laboratory but also for an infusion of improved technology at work in the power system. The chief impediments to this are institutional; they can be resolved through a proactive national consensus regarding institutional roles. Until this consensus is achieved, the lack of linkage between technology and policy may be a disruptive force in continued development of the national transmission grid and the broad infrastructures that it serves.

Listed below are several specific recommendations to address national transmission grid issues by creating a framework to accelerate the development and deployment of appropriate advanced technologies.

- Establish incentives for both private and public sector investment in RD&D. While federally funded basic research is important, ultimately it is the commercial sector that should move technology from the research lab to the marketplace. There is a need to accelerate the transition process within the electricity industry to reduce uncertainties regarding the future structure of generation and transmission markets since such uncertainties greatly impede investment in RD&D.

- Develop performance metrics for the national transmission grid where performance measures can be used to determine minimum planning and operational standards. These outcome-based measures would be consistent with the goals of the national transmission grid where issues such as serving the public good, promoting the economy, and ensuring national security can be balanced against the profit motivation associated with individual companies engaged in the electricity sector. Such a framework provides an incentive for private and public funding to research, develop, and deploy advanced technology because the linkage between enhanced performance associated with advanced technologies can be mapped to specific goals, with emphasis upon those technologies that cost effectively address poor performance according to these established measures.

- Apply a user fee to all institutions that engage in energy business. This fund will be used for energy R&D that is performed in the public interest, and all R&D results will be available to all institutions that engage in energy business.

- Stimulate the research, development, testing, and deployment of cost-effective technologies that allow greater capacity in existing right-of-ways. This includes passive reinforcement (e.g., advanced conductors and transmission configurations), active reinforcements (e.g., FACTS, HVDC, energy storage, and non-transmission technologies), and advanced information resources and controls that facilitate best use of transmission resources while ensuring system reliability.

- Promote programs that provide opportunities for energy consumers to manage their distributed energy resources (generation, storage, and load) in response to competitive market forces, including increased price visibility, demand-side participation in energy and ancillary services markets, and removal of technical and institutional barriers to distributed energy resources.

- Provide a forum for an industry-wide discussion to reach consensus on information access and dissemination issues. Certain information on system operations should be made broadly available to encourage markets to function, yet other information may be proprietary or sensitive.

- Establish security standards (both physical and cyber) for protecting the national transmission grid from attacks of malicious intent. Such standards should be derived from ongoing research in recognition of the evolving threat against the National critical civilian infrastructures.

- Draw upon the Federal utilities as a uniquely available and competent technical platform for inclusion in an expanded national RD&D infrastructure. Identify resources (facilities, staff, software, etc.) that do or could provide essential support to planning, development, and operation of the North America power system.

- Engage industry experts in the mentoring of R&D efforts and in the field assessments (demonstration projects) that are needed to close the gap between the development of new technology and its actual deployment for operational use. Give special attention to "critical path" enabling technologies that have not drawn sufficient commercial interest to assure their timely evaluation and refinement.

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Appendix A: List of New Technology Equipment to Reinforce the Transmission Grid

The transmission system of the future must not only have increased capacity to support the market demand for energy transactions, it must also be flexible to adapt to alterations in energy-delivery patterns. These patterns change at various time scales: hourly, daily, weekly, and seasonally. The transmission system must also adapt to delivery patterns dictated by the evolving geographical distribution of load and generation. As generation planning and dispatch decision making are placed in the hands of organizations other than utilities, new technologies that afford transmission planners a wider range of alternatives for deployment of power become more attractive.

This appendix lists some of the newer hardware technologies that are being researched and deployed to reinforce grid operations. The range of potential technologies is enormous. This appendix is limited to the hardware technologies that are most directly applicable to grid operations; the list presented is not exhaustive. Software technologies are discussed in the body of the paper and are not addressed here.

The appendix organizes hardware technologies into the following categories:

- Passive reinforcing equipment,
- Active reinforcing equipment, and
- Real-time monitoring equipment.

Within each category, we list the relevant technologies and summarize the primary objective, benefits, barriers to deployment, and commercial status of each.

Passive Reinforcing Equipment

This section discusses the potential impacts of new technologies associated with AC transmission lines and related equipment (transformers, capacitors, switch gear, etc.). This category includes the increased value (capacity per unit cost of installation, operation, and maintenance) obtained through new conductor materials and transmission line configurations as well as the flexibility gained to reconfigure the transmission system through greater modularity of transmission equipment.

Passive AC devices constitute by far the majority of the existing network. Though new lines will certainly be needed to reinforce the grid, the siting of these lines will continue to be a major challenge. Getting the most out of existing rights of way minimizes the need for new lines and rights of way and can minimize the societal concerns associated with visual pollution and high-energy EMFs.

Conductors

Advances in conductor technology fall into the areas of composite materials, and high-temperature superconductors.

High-Temperature Super-Conducting (HTSC) Technology: The conductors in HTSC devices operate at extremely low resistances. They require refrigeration (generally liquid nitrogen) to super-cool ceramic super-conducting material.

Objective: Transmit more power in existing or smaller rights of way. Used for transmission lines, transformers, reactors, capacitors, and current limiters.

Benefits: Cable occupies less space (AC transmission lines bundle three phase together; transformers and other equipment occupy smaller footprint for same level of capacity). Cables can be buried to reduce exposure to EMFs and counteract visual pollution issues. Transformers can reduce or eliminate cooling oils that, if spilled, can damage the environment. The HTSC itself can have a long lifetime, sharing the properties noted for surface cables below.

Barriers: Maintenance costs are high (refrigeration equipment is required and this demands trained technicians with new skills; the complexity of system can result in a larger number of failure scenarios than for current equipment; power surges can quench (terminate superconducting properties) equipment requiring more advanced protection schemes).

Commercial Status: A demonstration project is under way at Detroit Edison's Frisbie substation. Four-hundred-foot cables are being installed in the substation. Self-contained devices, such as current limiters, may be added to address areas where space is at a premium and to simplify cooling.

Below-Surface Cables: The state of the art in underground cables includes fluid-filled polypropylene paper laminate (PPL) and extruded dielectric polyethylene (XLPE) cables. Other approaches, such as gas-insulated transmission lines (GIL), are being researched and hold promise for future applications.

Objective: Transmit power in areas where overhead transmission is impractical or unpopular.

Benefits: The benefits compared with overhead transmission lines include protection of cable from weather, generally longer lifetimes, and reduced maintenance. These cables address environmental issues associated with EMFs and visual pollution associated with transmission lines.

Barriers: Drawbacks include costs that are five to 10 times those of overhead transmission and challenges in repairing and replacing these cables when problems arise. Nonetheless, these cables represent have made great technical advances; the typical cost ratio a decade ago was 20 to one.

Commercial Status: PPL cable technology is more mature than XLPE. EHV (extra high voltage) VAC and HVDC applications exist throughout the world. XLPE is gaining quickly and has advantages: low dielectric losses, simple maintenance, no insulating fluid to affect the environment in the event of system failure, and ever-smaller insulation thicknesses. GILs feature a relatively large-diameter tubular conductor sized for the gas insulation surrounded by a solid metal sleeve. This configuration translates to lower resistive and capacitive losses, no external EMFs, good cooling properties, and reduced total life-cycle costs compared with other types of cables. This type of transmission line is installed in segments joined with orbital welders and run through tunnels. This line is less flexible than the PPL or XLPE cables and is, thus far, experimental and significantly more expensive than those two alternatives.

Underwater application of electric cable technology has a long history. Installations are numerous between mainland Europe, Scandinavia, and Great Britain. This technology is also well suited to the electricity systems linking islands and peninsulas, such as in Southeast Asia. The Neptune Project consists of a network of underwater cables proposed to link Maine and Canada Maritime generation with the rest of New England, New York, and the mid-Atlantic areas.

Advanced Composite Conductors: Usually, transmission lines contain steel-core cables that support strands of aluminum wires, which are the primary conductors of electricity. New cores developed from composite materials are proposed to replace the steel core.

Objective: Allow more power through new or existing transmission rights of way.

Benefits: A new core consisting of composite fiber materials shows promise as stronger than steel-core aluminum conductors while 50 percent lighter in weight with up to 2.5 times less sag. The reduced weight and higher strength equate to greater current carrying capability as more current-carrying aluminum can be added to the line. This fact along with manufacturing advances, such as trapezoidal shaping of the aluminum strands, can reduce resistance by 10 percent, enable more compact designs with up to 50 percent reduction in magnetic fields, and reduce ice buildup compared to standard wire conductors. This technology can be integrated in the field by most existing reconductoring equipment.

Barriers: More experience is needed with the new composite cores to reduce total life-cycle costs.

Commercial Status: Research projects and test systems are in progress.

Transmission Line Configurations

Advances are being made in the configuration of transmission lines. New design processes coupled with powerful computer programs can optimize the height, strength, and positioning of transmission towers, insulators, and associated equipment in order to meet engineering standards appropriate for the conductor (e.g., distance from ground and tension for a given set of weather parameters).

Tower Design Tools: A set of tools is being perfected to analyze upgrades to existing transmission facilities or the installation of new facilities to increase their power-transfer capacity and reduce maintenance.

Objective: Ease of use and greater application of visualization techniques make the process more efficient and accurate when compared to traditional tools. Traditionally, lines have been rated conservatively. Careful analysis can discover the unused potential of existing facilities. Visualization tools can show the public the anticipated visual impact of a project prior to commencement.

Benefits: Avoids new right-of-way issues. The cost of upgrading the thermal rating has been estimated at approximately $7,000 per circuit mile, but reconductoring a 230-kV circuit costs on the order of $120,000 per mile compared with $230,000 per mile for a new steel-pole circuit (Lionberger and Duke 2001).

Barriers: This technology is making good inroads.

Commercial Status: Several companies offer commercial products and services.

Six-Phase and 12-Phase Transmission Line Configurations: The use of more than three phases for electric power transmission has been studied for many years. Using six or even 12 phases allows for greater power transfer capability within a particular right of way, and reduced EMFs because of greater phase cancellation. The key technical challenge is the cost and complexity of integrating such high-phase-order lines into the existing three-phase grid.

Modular Equipment

One way to gain flexibility for changing market and operational situations is to develop standards for the manufacture and integration of modular equipment.

Objective: Develop substation designs and specifications for equipment manufacturers to meet that facilitate the movement and reconfiguration of equipment in a substation to meet changing needs.

Benefits: Reduces overall the time and expense for transmission systems to adapt to the changing economic and reliability landscape.

Barriers: Requires transmission planners and substation designers to consider a broad range of operating scenarios. Also, developing industry standards can take a significant period, and manufacturers would need to offer conforming products.

Commercial Status: Utilities have looked for a certain amount of standardization and flexibility in this area for some time; however, further work remains to be done. National Grid (UK) has configured a number of voltage-support devices that use modular construction methods. As the system evolves, the equipment can be moved to locations where support is needed (PA Consulting Group 2001).

Universal Transformer: A single, standardized design capable of handling multiple voltage transformations in the mid ranges of 161/230/345/500 kV on a switch-selectable basis. Added features might be high portability, to facilitate emergency deployment from a “strategic reserve” of such transformers, plus the accommodation of high phase order transmission lines.

Exotic Transmission Alternatives

The following technical approaches have been proposed to reduce losses, increase capacity, and/or address situations where traditional energy transport mechanisms have shortcomings. In all cases, test configurations have been developed, but commercial implementations have yet to emerge.

Power Beaming (Wireless Power Transmission): Power beaming involves the wireless transmission of electric energy by means of either laser or microwave radiation. Near-term applications include transmission of electric energy for space applications (e.g., to orbiting satellites) from either a terrestrial- or space-based power generation platform. Other applications that have been studied include supporting human space exploration (e.g., lunar or Mars missions). Future applications might involve the beaming of energy from orbiting or even lunar-based solar power generators to terrestrial receivers, but to date the economics of such a system have remained elusive; proponents of such systems believe that they can be competitive within 15 to 25 years.

Ultra-High Voltage Levels: Because power is equal to the product of voltage times current, a highly effective approach to increasing the amount of power transmitted on a transmission line is to increase its operating voltage. Since 1969, the highest transmission voltage levels in North America have been 765 kV, (voltage levels up to 1,000 kV are in service elsewhere). Difficulties with utilizing higher voltages include the need for larger towers and larger rights of way to get the necessary phase separation, the ionization of air near the surface of the conductors because of high electric fields, the high reactive power generation of the lines, and public concerns about EMFs.

Active Reinforcing Equipment

Transmission System Devices

Implemented throughout the system, these devices include capacitors, phase shifters, static-var compensators (SVCs), thyristor-controlled series capacitors (TCSC), thyristor-controlled dynamic brakes, and other similar devices. Used to adjust system impedance, these devices can increase the transmission system's transfer capacity, support bus voltages by providing reactive power, or enhance dynamic or transient stability.

HVDC: With active control of real and reactive power transfer, HVDC can be modulated to damp oscillations or provide power-flow dispatch independent of voltage magnitudes or angles (unlike conventional AC transmission).

Objective: HVDC is used for long-distance power transport, linking asynchronous control areas, and real-time control of power flow.

Benefits: Stable transport of power over long distances where AC transmission lines need series compensation that can lead to stability problems. HVDC can run independent of system frequency and can control the amount of power sent through the line. This latter benefit is the same as for FACTS devices discussed below.

Barriers: Drawbacks include the high cost of converter equipment and the need for specially trained technicians to maintain the devices.

Commercial Status: Many long-distance HVDC links are in place around the world. Back-to-back converters link Texas, WSCC, and the Eastern Interconnection in the US. More installations are being planned.

FACTS Compensators: Flexible AC Transmission System (FACTS) devices use power electronics to adjust the apparent impedance of the system. Capacitor banks are applied at loads and substations to provide capacitive reactive power to offset the inductive reactive power typical of most power system loads and transmission lines. With long inter-tie transmission lines, series capacitors are used to reduce the effective impedance of the line. By adding thyristors to both of these types of capacitors, actively controlled reactive power is available using SVCs and TCSC devices, which are shunt- and series-controlled capacitors, respectively. The thyristors are used to adjust the total impedance of the device by switching individual modules. Unified power-flow controllers (UPFCs) also fall into this category.

Objective: FACTS devices are designed to control the flow of power through the transmission grid.

Benefits: These devices can increase the transfer capacity of the transmission system, support bus voltages by providing reactive power, or be used to enhance dynamic or transient stability.

Barriers: As with HVDC, the power electronics are expensive and specially trained technicians are needed to maintain them. In addition, experience is needed to fully understand the coordinated control strategy of these devices as they penetrate the system.

Commercial Status: As mentioned above, the viability of HVDC systems has already been demonstrated. American Electric Power (AEP) has installed a FACTS device in its system, and a new device was recently commissioned by the New York Power Authority (NYPA) to regulate flows in the northeast.

FACTS Phase-Shifting Transformers: Phase shifters are transformers configured to change the phase angle between buses; they are particularly useful for controlling the power flow on the transmission network. Adding thyristor control to the various tap settings of the phase-shifting transformer permits continuous control of the effective phase angle (and thus control of power flow).

Objective: Adjust power flow in the system.

Benefits: The key advantage of adding power electronics to what is currently a non-electronic technology is faster response time (less then one second vs. about one minute). However, traditional phase shifters still permit redirection of flows and thereby increase transmission system capacity.

Barriers: Traditional phase shifters are deployed today. The addition of the power electronics to these devices is relatively straightforward but increases expense and involves barriers similar to those noted for FACTS compensators.

Commercial Status: Tap-changing phase shifters are available today. Use of thyristor controls is emerging.

FACTS Dynamic Brakes: A dynamic brake is used to rapidly extract energy from a system by inserting a shunt resistance into the network. Adding thyristor controls to the brake permits addition of control functions, such as on-line damping of unstable oscillations.

Objective: Dynamic brakes enhance power system stability.

Benefits: This device can damp unstable oscillations triggered by equipment outages or system configuration changes.

Barriers: In addition the power electronics issues mentioned earlier, siting a dynamic brake and tuning the device in response to specific contingencies requires careful study.

Commercial Status: BPA has installed a dynamic brake on their system.

Energy-Storage Devices

The traditional function of an energy-storage device is to save production costs by holding cheaply generated off-peak energy that can be dispatched during peak-consumption periods. By virtue of its attributes, energy storage can also provide effective power system control with modest incremental investment. Different dispatch modes can be superimposed on the daily cycle of energy storage, with additional capacity reserved for the express purpose of providing these control functions.

Batteries: Batteries use converters to transform the DC in the storage device to the AC of the power grid. Converters also operate in the opposite direction to recharge the batteries.

Objective: Store energy generated in off-peak hours to be used for emergencies or on-peak needs.

Benefits: Battery converters use thyristors that, by the virtue of their ability to rapidly change the power exchange, can be utilized for a variety of real-time control applications ranging from enhancing transient to preconditioning the area control error for automatic generator control enhancement. During their operational lifetime, batteries have a small impact on the environment. For distributed resources, batteries do not need to be as large as for large-scale generation, and they become important components for regulating micro-grid power and allowing interconnection with the rest of the system.

Barriers: The expense of manufacturing and maintaining batteries has limited their impact in the industry.

Commercial Status: Several materials are used to manufacture batteries though large arrays of lead-acid batteries continue to be the most popular for utility installations. Interest is also growing in so-called "flow batteries" that charge and discharge a working fluid exchanged between two tanks. The emergence of the distributed energy business has increased the interest in deploying batteries for regional energy storage. One of the early battery installations that demonstrated grid benefit was a joint project between EPRI and Southern California Edison at the Chino substation in southern California.

Super-conducting Magnetic Energy Storage (SMES): SMES uses cryogenic technology to store energy by circulating current in a super-conducting coil.

Objective: Store energy generated in off-peak hours to be used for emergencies or on-peak needs.

Benefits: The benefits are similar to those for batteries. SMES devices are efficient because of their super-conductive properties. They are also very compact for the amount of energy stored.

Barriers: As with the super-conducting equipment mentioned in the passive equipment section above, SMES entails costs for the cooling system, the special protection needed in the event the super-conducting device quenches, and the specialized skills required to maintain the device.

Commercial Status: Several SMES units have been commissioned in North America. They have been deployed at Owens Corning to protect plant processes, and at Wisconsin Public Service to address low-voltage and grid instability issues.

Pumped Hydro and Compressed-Air Storage: Pumped hydro consists of large ponds with turbines that can be run in either pump or generation modes. During periods of light load (e.g., night) excess, inexpensive capacity drives the pumps to fill the upper pond. During heavy load periods, the water generates electricity into the grid. Compressed air storage uses the same principle except that large, natural underground vaults are used to store air under pressure during light-load periods.

Objective: This technology helps shave peak and can help in light-load, high-voltage situations.

Benefits: These storage systems behave like conventional generation and have the benefit of producing additional generation sources that can be dispatched to meet various energy and power needs of the system. Air emission issues can be mitigated when base generation is used in off-peak periods as an alternative to potentially high-polluting peaking units during high use periods.

Barriers: Pumped hydro, like any hydro generation project, requires significant space and has corresponding ecological impact. The loss of efficiency between pumping and generation as well as the installation and maintenance costs must be outweighed by the benefits.

Commercial Status: Pumped hydro projects are sprinkled across North America. A compressed-air storage plant was built in Alabama, and a proposed facility in Ohio may become the world's largest.

Flywheels: Flywheels spin at high velocity to store energy. As with pumped hydro or compressed-air storage, the flywheel is connected to a motor that either accelerates the flywheel to store energy or draws energy to generate electricity. The flywheel rotors are specially designed to significantly reduce losses. Super conductivity technology has also been deployed to increase efficiency.

Objective: Shave peak energy demand and help in light-load, high-voltage situations. As a distributed resource, flywheels enhance power quality and reliability.

Benefits: Flywheel technology has reached low-loss, high-efficiency levels using rotors made of composite materials running in vacuum spaces. Emissions are not an issue for flywheels, except those related to the energy expended to accelerate and maintain the flywheel system.

Barriers: The use of super-conductivity technology faces the same barriers as noted above under super-conducting cables and SMES. High-energy-storage flywheels require significant space and the high-speed spinning mass can be dangerous if the equipment fails.

Commercial Status: Flywheel systems coupled with batteries are making inroads for small systems (e.g., computer UPS, local loads, electric vehicles). Flywheels rated in the 100 to 200 kW range are proposed for development in the near term.

Controllable Load

Fast-acting load control is an important element in active measures for enhancing the transmission grid. Automatic load shedding (under-frequency, under-voltage), operator-initiated interruptible load, demand-side management programs, voltage reduction, and other load-curtailment strategies have long been an integral part of coping with unforeseen contingencies as a last resort, and/or as a means of assisting the system during high stress, overloaded conditions. Future advances in load-control technology will leverage the advent of real-time pricing, enabling consumers to "back off" their loads (either automatically through grid-friendly appliances or through manual intervention) when the price is right.

Price-Responsive Load: The electricity industry has been characterized by relatively long-term contracts for electricity use. As the industry restructures to be more market-driven, adjusting demand based on market signals will become an important tool for grid operators.

Objective: Inform energy users of system conditions though price signals that nudge consumption into positions that make the system more reliable and economic.

Benefits: The approach reduces the need for new transmission and siting of new generation. Providing incentives to change load in appropriate regions of the system can stabilize energy markets and enhance system reliability. Shifting load from peak periods to less polluting off-peak periods can reduce emissions.

Barriers: The vast number of loads in the system make communication and coordination difficult. Also, using economic signals in real time or near-real time to affect demand usage has not been part of the control structure that has been used by the industry for decades. A common vision and interface standards are needed to coordinate the information exchange required.

Commercial Status: Demand-management programs have been implemented in various areas of the country. These have relied on centralized control. With the advent of the Internet and new distributed information technology approaches, firms are emerging to take advantage of this technology with a more distributed control strategy.

Intelligent Building Systems: Energy can be saved through increasing the efficient operation of buildings and factories. Coordinated utilization of cooling, heating, and electricity in these establishments can significantly reduce energy consumption. Operated in a system that supports price-responsive load, intelligent building systems can benefit system operations. Note: these systems may have their own, local generation. Such systems have the option of selling power to the grid as well as buying power.

Objective: Reduce energy costs and provide energy management resources to stabilize energy markets and enhance system reliability.

Benefits: Such systems optimize energy consumption for the building operators and may provide system operators with energy by reducing load or increasing local generation based on market conditions.

Barriers: These systems require a greater number of sensors and more complex control schemes than are common today. Should energy market access become available at the building level, the price incentives would increase.

Commercial Status: Pilot projects have been implemented throughout the country.

Generation

Devices that are designed to improve the efficiency or interface of generation resources can be used for power system control. Advanced converter concepts will play an increasing role, providing power conversion between DC and AC power, for resources such as wind, solar, and any non-synchronous generation. Converter concepts such as pulse width modulation and step-wave inverters would be particularly useful for incorporating DC sources into the grid or providing an asynchronous generation interface. Asynchronous generation has been proposed for increasing the efficiency of hydroelectric generation, which would also have the advantage of providing control functions such as the ability to modify the effective inertia of generators.

Distributed Generation (DG): Fuel cells, micro-turbines, diesel generators, and other technologies are being integrated using power electronics. As these distributed resources increase in number, they can become a significant resource for reliable system operations. Their vast numbers and teaming with local load put them in a similar category to the controllable load discussed above.

Objective: Address local demand cost-effectively.

Benefits: DG is generally easier to site, entails smaller individual financial outlay, and can be more rapidly installation than large-scale generation. DG can supply local load or sell into the system and offers owners self-determination. Recovery and use of wase heat from some DG greatly increases energy efficiency.

Barriers: Volatility of fuel costs and dependence on the fuel delivery infrastructure creates financial and reliability risks. DG units require maintenance and operations expertise, and utilities can set up discouraging rules for interconnection. System operators have so far had difficulty coordinating the impact of DG.

Commercial Status: Deployment of DG units continues to increase. As with controllable load, system operations are recognizing the potential positive implications of DG to stabilize market prices and enhance system reliability though this requires a different way of thinking from the traditional, hierarchical control paradigm.

Real-time Monitoring

This section discusses the impact of new hardware technology on the capacity to sense in real time the loading and limits of individual system devices as well as the overall state of the system. The capability of the electricity grid is restricted through a combination of the limits on individual devices and the composite loadability of the system. Improving monitoring to determine these limits in real time and to measure the system state directly can increase grid capability.

Power-System Device Sensors

The operation of most of the individual devices in a power system (such as transmission lines, cables, transformers, and circuit breakers) is limited by each device's thermal characteristics. In short, trying to put too much power through a device will cause it to heat excessively and eventually fail. Because the limits are thermal, their actual values are highly dependent upon each device's heat dissipation, which is related to ambient conditions. The actual flow of power through most power-system devices is already adequately measured. The need is for improved sensors to dynamically determine the limits by directly or indirectly measuring temperature.

Direct Measurement of Conductor Sag: For overhead transmission lines the ultimate limiting factor is usually conductor sag. As wires heat, they expand, causing the line to sag. Too much sag will eventually result in a short circuit because of arcing from the line to whatever is underneath.

Objective: Dynamically determine line capacity by directly measuring the sag on critical line segments.

Benefits: Dynamically determined line ratings allow for increased power capacity under most operating conditions.

Barriers: Requires continuous monitoring of critical spans. Cost depends on the number of critical spans that must be monitored, the cost of the associated sensor technology, and ongoing cost of communication.

Commercial Status: Pre-commercial units are currently being tested. Approaches include either video or the use of differential GPS. EPRI currently is testing a video-based "sagometer." An alternative is to use differential GPS to directly measure sag. Differential GPS has been demonstrated to be accurate significantly below half a meter.

Indirect Measurement of Conductor Sag: Transmission line sag can also be estimated by physically measuring the conductor temperature using an instrument directly mounted on the line and/or a second instrument that measures conductor tension at the insulator supports.

Objective: Dynamically determine the line capacity.

Benefits: Dynamically determined line ratings allow for increased power capacity under most operating conditions.

Barriers: Requires continuous monitoring of critical spans. Cost depends upon the number of critical spans that must be monitored, the cost of the associated sensor technology, and ongoing costs of communication.

Commercial Status: Commercial units are available.

Indirect Measurement of Transformer Coil Temperature: Similar to transmission line operation, transformer operation is limited by thermal constraints. However, transformers constraints are localized hot spots on the windings that result in breakdown of insulation.

Objective: Dynamically determine transformer capacity.

Benefits: Dynamically determined transformer ratings allow for increased power capacity under most operating conditions.

Barriers: The simple use of oil temperature measurements is usually considered to be unreliable.

Commercial Status: Sophisticated monitoring tools are now commercially available that combine several different temperature and current measurements to dynamically determine temperature hot spots.

Underground/Submarine Cable Monitoring/Diagnostics: The below-surface cable systems described above require real-time monitoring to maximize their use and warn of potential failure.

Objective: Incorporate real-time sensing equipment to detect potentially hazardous operating situations as well as dynamic limits for safe flow of energy.

Benefits: Monitoring equipment maximizes the use of the transmission asset, mitigates the risk of failure and the ensuing expense of repair, and supports preventive maintenance procedures. The basic sensing and monitoring technology is available today.

Barriers: The level of sophistication of the sensing and monitoring equipment adds to the cost of the cable system. The use of dynamic limits must also be integrated into system operation procedures and the associated tools of existing control facilities.

Commercial Status: Newer cable systems are being designed with monitoring/diagnostics in mind. Cable temperature, dynamic thermal rating calculations, partial discharge detection, moisture ingress, cable damage, hydraulic condition (as appropriate), and loss detection are some of the sensing functions being put in place. Multifunctional cables are also being designed and deployed (particularly submarine cables) that include communications capabilities. Monitoring is being integrated directly into the manufacturing process of these cables.

Direct System-State Sensors

In some situations, transmission capability is not limited by individual devices but rather by region-wide dynamic loadability constraints. These include transient stability limitations, oscillatory stability limitations, and voltage stability limitations. Because the time frame associated with these phenomena is much shorter than that associated with thermal overloads, predicting, detecting and responding to these events requires much faster real-time state sensors than for thermal conditions. The system state is characterized ultimately by the voltage magnitudes and angles at all the system buses. The goal of these sensors is to provide these data at a high sampling rate.

Power-System Monitors

Objective: Collect essential signals (key power flows, bus voltages, alarms, etc.) from local monitors available to site operators, selectively forwarding to the control center or to system analysts.

Benefits: Provides regional surveillance over important parts of the control system to verify system performance in real time.

Barriers: Existing SCADA and Energy Management Systems provide low-speed data access for the utility's infrastructure. Building a network of high-speed data monitors with intra-regional breadth requires collaboration among utilities within the interconnected power system.

Commercial Status: BPA has developed a network of dynamic monitors collecting high-speed data, first with the power system analysis monitor (PSAM), and later with the portable power system monitor (PPSM), both early examples of WAMS products.

Phasor Measurement Units (PMUs)

Objective: PMUs are synchronized digital transducers that can stream data, in real time, to phasor data concentrator (PDC) units. The general functions and topology for this network resemble those for dynamic monitor networks. Data quality for phasor technology appears to be very high, and secondary processing of the acquired phasors can provide a broad range of signal types.

Benefits: Phasor networks have best value in applications that are mission critical and that involve truly wide-area measurements.

Barriers: Establishing PMU networks is straightforward and has already been done. The primary impediment is cost and assuring value for the investment (making best use of the data collected).

Commercial Status: PMU networks have been deployed at several utilities across the country.